WHITING PETROLEUM CORP
Form 424A
November 05, 2004
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The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Filed Pursuant to Rule 424(a)

Registration No. 333-118261

Subject to Completion

Preliminary Prospectus Dated November 4, 2004

PROSPECTUS

7,500,000 Shares

Whiting Petroleum Corporation

Common Stock

We are offering 7,500,000 shares of our common stock. Our common stock trades on the New York Stock Exchange under the symbol WLL. On November 3, 2004, the last sale price of our common stock as reported on the New York Stock Exchange was $29.85 per share.

Investing in our common stock involves risks that are described in the Risk Factors section beginning on page 16 of this prospectus.

	Per Share	Total
Public offering price	$	$
Underwriting discount	$	$

Proceeds, before expenses, to us	$	$

The underwriters may also purchase up to an additional 1,125,000 primary shares from us at the public offering price, less the underwriting discount, within 30 days from the date of this prospectus to cover

overallotments.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The shares will be ready for delivery on or about , 2004.

Merrill Lynch & Co.

Sole Book-Running Manager

A.G. Edwards

Banc of America Securities LLC

JPMorgan

Raymond James **Petrie Parkman & Co.**

KeyBanc Capital Markets **Simmons & Company International**

The date of this prospectus is , 2004.

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Unless the context otherwise requires, references in this prospectus to Whiting, we, us, our or ours refer to Whiting Petroleum Corporation, together with its operating subsidiaries. When the context requires, we refer to these entities separately. References in this prospectus to Resources refer to Alliant Energy Resources, Inc., a wholly-owned subsidiary of Alliant Energy Corporation. References in this prospectus to Alliant Energy refer to Alliant Energy Corporation.

You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. You should assume that the information appearing in this prospectus is accurate only as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

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PROSPECTUS SUMMARY

This summary highlights selected information contained elsewhere in this prospectus. You should read this entire prospectus carefully, including Risk Factors and our financial statements and the notes to those financial statements included elsewhere in this prospectus. We have provided definitions for the oil and natural gas terms used in this prospectus in the Glossary of Oil and Natural Gas Terms included in this prospectus. The reserve information and other related operating statistics contained in this prospectus are as of January 1, 2004 unless otherwise indicated.

About Our Company

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California regions of the United States. Our focus is on pursuing growth projects that we believe will generate attractive rates of return and maintaining a balanced portfolio of lower risk, long-lived oil and natural gas properties that provide stable cash flows.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through both property acquisitions and exploitation activities. As of January 1, 2004, our estimated proved reserves totaled 438.8 Bcfe, of which 75% were classified as proved developed. These estimated reserves had a pre-tax PV10% value of approximately $784.6 million, of which approximately 85% came from properties located in three states: Texas, North Dakota and Michigan. During 2003, we spent approximately $52.0 million on capital projects, including $38.8 million for the drilling of 72 gross (24.8 net) wells (64 successful completions and eight uneconomic wells), representing an 89% success rate. We have budgeted approximately $80.0 million for capital expenditures in 2004. Through September 30, 2004, we have invested $52.8 million of our budgeted expenditures for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate.

As of January 1, 2004, we had a balanced portfolio of oil and natural gas reserves, with approximately 53% of our proved reserves consisting of natural gas and approximately 47% consisting of oil. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to trailing 12 month production ending December 31, 2003 of approximately 11.8 years.

During 2004, we completed five separate acquisitions of producing properties with a combined purchase price of $516.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe, representing an average cost of approximately $1.22 per Mcfe of estimated proved reserves. We will continue to seek property acquisition opportunities that complement our existing core properties. We believe that our exploitation and acquisition expertise and our drilling inventory, together with our operating experience and efficient cost structure, provide us with the potential to continue our growth.

As of October 1, 2004, which includes the impact of these five acquisitions, our estimated proved reserves totaled 867.3 Bcfe, representing a 98% increase in proved reserves since January 1, 2004. Natural gas made up 39.0% of total proved reserves and 72% were classified as proved developed. Of these reserves, 38.8% were located in the Rocky Mountain region, 31.6% in the Permian Basin, 13.4% in the Gulf Coast, 11.4% in Michigan, 3.2% in the Mid-Continent region and 1.6% in California. Our estimated October 2004 average daily production is 177.7 MMcfe, representing a 75% increase over December 2003 average daily production and implying an average reserve life of approximately 13.4 years.

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The following table summarizes our estimated proved reserves and pre-tax PV10% value within our core areas as of October 1, 2004 and our estimated October 2004 average daily production, each of which includes the impact of these five acquisitions.

	Proved Reserves					October 2004
Core Area	Oil (MMbbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	Pre-Tax PV10% Value (In millions)	Average Daily Production (MMcfe)
Permian Basin	37.7	47.9	274.2	17.5%	$ 731.5	41.4
Rocky Mountains[1]	43.3	76.3	336.4	22.7%	$ 716.1	65.1
Gulf Coast	3.3	96.2	115.8	83.0%	$ 324.2	39.2
Michigan	1.9	87.8	99.1	88.6%	$ 219.1	21.0
Mid-Continent	2.0	15.7	27.9	56.4%	$ 61.8	6.2
California	0.0	14.0	14.0	100.0%	$ 35.2	4.9
Total	88.2	337.9	867.3	39.0%	$ 2,087.9	177.7

(1) Includes one field in Canada with total estimated proved reserves of 5.2 Bcfe and a pre-tax PV10% value of $14.0 million.

Recent Acquisitions

The following table summarizes certain information about the purchase price, estimated proved reserves and pre-tax PV10% value as of October 1, 2004 and estimated October 2004 average daily production for the five recent acquisitions described below.

		Proved Reserves						October 2004
	Purchase Price (In millions)	Oil (MMbbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	% Developed	Pre-Tax PV 10% Value (In millions)[6]	Average Daily Production (MMcfe)
Permian Basin[1] Properties	$ 345.0	34.2	44.6	250.0	17.8%	59%	$ 673.6	36.4
Equity Oil Company[2]	$ 72.6	10.2	42.1	103.6	40.6%	69%	$ 217.6	16.1
Colorado/ Wyoming[3]	$ 44.2	3.4	19.4	40.1	48.4%	82%	$ 76.6	8.6
Wyoming/Utah[4]	$ 35.0	3.6	11.1	32.6	34.1%	92%	$ 64.5	6.1
Louisiana/Texas[5]	$ 19.3	0.5	10.7	13.9	76.9%	57%	$ 39.5	3.5
Subtotal Acquisitions	$ 516.1	52.0	127.9	440.1	29.1%	66%	$ 1,071.8	70.7
Whiting Historical		36.2	210.0	427.2	49.2%	78%	$ 1,016.1	107.0

Total	88.2	337.9	867.3	39.0%	72%	$ 2,087.9	177.7

(1) Proved reserves are based on the reserve report prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers, as of July 1, 2004. Revenues and volumes are included in our results beginning September 23, 2004.

(2) Proved reserves are based on the reserve report prepared by Ryder Scott Company, L.P., independent petroleum engineers, as of December 31, 2003. Equity s results of operations and volumes are included in our results beginning July 20, 2004.

(3) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning August 13, 2004.

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(4) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning September 30, 2004.

(5) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning August 16, 2004.

(6) These amounts were calculated using a period end average realized oil price of $45.87 per barrel and a period end average realized natural gas price of $5.64 per Mcf.

Permian Basin Properties

On September 23, 2004, we acquired interests in seventeen fields in the Permian Basin of West Texas and Southeast New Mexico, including interests in key fields such as Parkway Field in Eddy County, New Mexico; Would Have and Signal Peak Fields in Howard County, Texas; Keystone Field in Winkler County, Texas; and the DEB Field in Gaines County, Texas. The purchase price was $345.0 million in cash and was funded through borrowings under our bank credit agreement.

For the year ended December 31, 2003, these properties reported revenues in excess of direct operating expenses of $72.1 million. As of October 1, 2004, these properties had 250.0 Bcfe of estimated proved reserves, of which 17.8% were natural gas and 59% were classified as proved developed, and had a pre-tax PV10 value of estimated proved reserves of $673.6 million. The estimated October 2004 average daily production for these properties is approximately 36.4 MMcfe, implying an average reserve life of 18.8 years. We operate approximately 72% of the average daily production from these properties.

Low Cost Acquisition in Core Operational Area. Based on the purchase price of $345.0 million and estimated proved reserves of 251.6 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.37 per Mcfe of estimated proved reserves. We added approximately 300 operated producing wells in our Permian Basin core area with this acquisition.

Attractive Operating Cost Profile. The acquired Permian Basin properties operating performance is characterized by low operating costs. This acquisition was also attractive because average lease operating expense for these properties over the past three years was $0.68 per Mcfe in contrast to our historical lease operating expense of $1.01 per Mcfe for the same period. Additionally, we expect the anticipated incremental general and administrative expense for these properties to be lower than that of our existing operations given its overlap with our current operations in the Permian Basin. Including the impact of this acquisition, our Permian Basin region is now nearly as large as our Rocky Mountains core area, representing 31.6% and 38.8% of our total proved reserves as of October 1, 2004, respectively.

Additional Development Opportunities. We expect to leverage our operational and technical expertise in this core area to fully exploit the potential these properties present. We plan to continue the development of the PUD and other non-producing reserves we have acquired through this acquisition, and believe that this development offers us the opportunity to increase the current rate of production.

Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our common stock to Equity s shareholders and repaid all of Equity s outstanding debt of $29.0 million under its credit facility. Equity s operations are focused primarily in California, Colorado, North Dakota and Wyoming.

For the year ended December 31, 2003, Equity reported income from continuing operations of $2.4 million, net cash provided by operating activities of $11.5 million and production of 6.6 Bcfe (45% natural gas). As of

October 1, 2004, Equity had 103.6 Bcfe of estimated proved reserves, of which 40.6% were natural gas and 69% were classified as proved developed, and had a pre-tax PV10% value of estimated proved reserves of approximately $217.6 million. The estimated October 2004 average daily production from these properties is approximately 16.1 MMcfe, implying an average reserve life of 17.6 years.

Based on the purchase price of $72.6 million and estimated proved reserves of 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Addition of Long-life, Stable Reserves. With a reserve life index of over 17 years, the long-life Equity reserves are predominately in mature and predictable fields.

Expansion of Exploration and Exploitation Opportunities. With over 75,000 net undeveloped acres and 375 square miles of 3-D seismic, the Equity properties have added to our inventory of exploration, development and exploitation opportunities. We expect our strong financial position to allow more rapid development of these opportunities than Equity s cash flow permitted.

Creates Synergies and Cost Savings. We anticipate that combining the complementary operations of the two companies will allow us to take advantage of synergies and to realize cost savings.

Other Cash Acquisitions of Properties

On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming from an undisclosed seller. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. We operate two of the fields and have an 84% average working interest in those fields. As of October 1, 2004, these interests had 40.1 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 8.6 MMcfe, implying an average reserve life of 12.7 years. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah from an undisclosed seller. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. As of October 1, 2004, these interests had 32.6 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 6.1 MMcfe, implying an average reserve life of 14.7 years. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas from Delta Petroleum Corporation. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. We operate two of the fields and have a 93% average working interest in those fields. As of October 1, 2004, these interests had 13.9 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 3.5 MMcfe, implying an average reserve life of 11.0 years. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe of estimated proved reserves.

Business Strategy

Our goal is to increase stockholder value by investing in oil and gas projects with attractive rates of return on capital employed. We plan to achieve this goal by exploiting and developing our existing oil and natural gas properties and pursuing acquisitions of additional properties. Specifically, we have focused, and plan to continue to focus, on the following:

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Developing and Exploiting Existing Properties. We believe that there is significant value to be created by drilling the numerous identified undeveloped opportunities on our properties. As of January 1, 2004, we owned interests in a total of 517,000 gross (206,000 net) developed acres. In addition, as of December 31, 2003, we owned interests in approximately 386,000 gross (188,000 net) undeveloped acres that contain many exploitation opportunities. During the three years ended December 31, 2003, we invested $94 million to participate in the drilling of 169 gross (60.6 net) wells, the majority of which were developmental wells, and 85.2% were successful completions. As of January 1, 2004, we had identified a total of 171 proved undeveloped drilling locations on our properties. We drilled or participated in the drilling of 72 gross (24.8 net) wells during the year ended December 31, 2003 and have budgeted approximately $80.0 million for the further development of our properties in 2004. Through September 30, 2004, we have invested $52.8 million of our budgeted expenditures for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate.

Pursuing Profitable Acquisitions. We have pursued and intend to continue to pursue acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have developed and refined an acquisition program designed to increase reserves and complement our existing core properties. We have an experienced team of management, engineering and geoscience professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties. During the first nine months of 2004, we completed five separate acquisitions of producing properties with a combined purchase price of $516.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe, representing a cost of $1.22 per Mcfe of estimated proved reserves. To secure attractive realized commodity prices on a portion of our volumes, we periodically enter into derivative contracts, typically no-cost collars. Given our recent acquisitions discussed above, and as an additional step toward realizing our profit potential from these acquisitions, we have increased our volumes subject to these collars to cover approximately 56% to 58% (excluding fixed price marketing contracts) of our natural gas volumes as of October 1, 2004 through December 2005 and between 55% and 75% of our crude oil volumes as of October 1, 2004 through December 2005. The average floor and ceiling for these volumes are approximately $4.60 and $9.59 per Mcf of natural gas, respectively, and $35.45 and $50.98 per bbl of crude oil, respectively.

Focusing on High Return Operated and Non Operated Properties. We have historically acquired operated as well as non operated properties that meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non operated property interests at attractive rates of return that provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non operated interests to the extent they meet our return criteria and further our growth strategy.

Controlling Costs through Efficient Operation of Existing Properties. We operate approximately 60% of the pre-tax PV10% value of our total proved reserves and approximately 82% of the pre-tax PV10% value of our proved undeveloped reserves, which we believe enables us to better manage expenses, capital allocation and the decision making processes related to our exploitation and exploration activities. For the year ended December 31, 2003, our lease operating expense per Mcfe averaged $1.16 and general and administrative costs averaged $0.34 per Mcfe produced, net of reimbursements.

Competitive Strengths

We believe that our key competitive strengths lie in our diversified asset base, our experienced management and technical team and our commitment to efficient utilization of new technologies.

Diversified Asset Base. As of January 1, 2004, we had interests in 5,006 wells in 16 states across our four core geographical areas of the United States. This property base, as well as our continuing business strategy of

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acquiring and developing properties in our core operating areas, presents us with a large number of opportunities for successful development and exploitation and additional acquisitions.

Experienced Management Team. Our management team averages 27 years of experience in the oil and natural gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 20 years of experience in the evaluation, acquisition and operational assimilation of oil and natural gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated detailed geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Our technical team has access to approximately 575 square miles of 3-D seismic data that we have assembled primarily over the past five years. A team with access to state of the art geophysical/ geological computer applications and hardware analyzes this information. Computer applications, such as the WellView® software system, enable us to quickly generate reports and schematics on our wells. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. This technology and expertise has greatly aided our pursuit of attractive development projects.

Recent Developments

New Credit Agreement

On September 23, 2004, Whiting Oil and Gas Corporation entered into a new $750.0 million credit agreement with a syndicate of banks. The new credit agreement increased our borrowing base to $480.0 million from $195.0 million under our prior credit agreement. On September 23, 2004, we borrowed $400.0 million under the credit agreement to refinance the entire outstanding balance under the prior credit agreement and to fund our $345.0 million acquisition of oil and natural gas producing properties in the Permian Basin. For more information about our credit agreement, see Management s Discussion and Analysis of Financial Condition and Results of Operation Liquidity and Capital Resources Credit Facility.

Recent Drilling Activity

During the first nine months of 2004, we have invested $52.8 million of our $80.0 million development budget for 2004 for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate. During the first nine months of 2004, our drilling activity has been primarily focused within our Northern Rocky Mountain and Gulf Coast core areas.

In South Texas, we have completed two successful Edwards wells in our Stuart City Reef Trend properties which are producing at a combined rate 5.9 MMcf per day. Also in this area, we completed three new Wilcox wells, which have a combined rate of 3.9 MMcf per day. Since June 30, 2004, production volumes in our Stuart City fields have increased by 62% to 14.6 MMcf per day.

In the Williston Basin, we have a new exploration program in western Billings County, North Dakota, targeting the Nisku Formation. Since June 30, 2004, we have drilled three new producing wells, which have a combined rate of 1,180 barrels of oil and 1.2 MMcf of natural gas per day as of October 11, 2004. We have an average 92.8% net revenue interest in these wells and we plan to drill five additional wells during 2004.

Corporate Information

Whiting Petroleum Corporation was incorporated in Delaware on July 18, 2003 for the sole purpose of becoming a holding company of Whiting Oil and Gas Corporation in connection with our initial public offering. Whiting Oil and Gas Corporation was incorporated in Delaware in 1983.

Our principal executive offices are located at 1700 Broadway, Suite 2300, Denver, Colorado 80290-2300, and our telephone number is (303) 837-1661.

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The Offering

Common stock offered	7,500,000 shares
Shares outstanding after the offering	28,600,347 shares
Concurrent offering by Resources	Resources is concurrently offering 1,080,000 shares of our outstanding common stock. Prior to our initial public offering in November 2003, we were a wholly-owned subsidiary of Resources, which is a wholly-owned subsidiary of Alliant Energy. Resources is offering all of the 1,080,000 shares of our common stock that it did not sell in our initial public offering and will own no shares of our common stock following its concurrent offering. The offering of our shares being made pursuant to this prospectus is not contingent on the successful completion of the concurrent offering of our shares by Resources.
Use of proceeds	We will use the net proceeds we receive from this offering to repay debt incurred in connection with the acquisitions described under Recent Acquisitions.
	We will not receive any proceeds from the concurrent sale of our shares by Resources.
Risk factors	Please read Risk Factors for a discussion of factors you should consider carefully before deciding to invest in shares of our common stock.
New York Stock Exchange symbol	WLL

The number of shares outstanding after the offering is based on 21,100,347 shares outstanding as of September 30, 2004. This number assumes that the underwriters over-allotment option is not exercised. If the over-allotment option is exercised in full, we will issue and sell an additional 1,125,000 primary shares.

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Summary Historical and Unaudited Pro Forma Financial Information

The summary historical financial information for the year ended December 31, 2003 has been derived from our audited consolidated financial statements and related notes. The summary historical financial information for the nine months ended September 30, 2004 has been derived from our unaudited consolidated financial statements and related notes. This information is only a summary and you should read it in conjunction with material contained in Management s Discussion and Analysis of Financial Condition and Results of Operations, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our financial statements and related notes included elsewhere in this prospectus. The unaudited interim period financial information, in our opinion, includes all adjustments, which are normal and recurring in nature, necessary for a fair presentation for the periods shown. Results for the nine months ended September 30, 2004 are not necessarily indicative of the results to be expected for the full fiscal year.

The summary unaudited pro forma financial information for the year ended December 31, 2003 and the nine months ended September 30, 2004 has been derived from our unaudited pro forma financial statements and related notes included elsewhere in this prospectus. This information is only a summary and you should read it in conjunction with material contained in Unaudited Pro Forma Financial Statements and our historical financial statements and related notes included elsewhere in this prospectus. This summary unaudited pro forma financial information gives effect to our recent acquisition of Permian Basin properties as if such transaction had occurred as of January 1, 2003. This summary unaudited pro forma financial information does not reflect the pro forma effect of any of our other recent acquisitions, this offering or the use of proceeds from this offering. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include results from our Wyoming and Utah acquisition that closed on September 30, 2004.

	Pro Forma for the Nine Months Ended September 30, 2004	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Pro Forma for the Year Ended December 31, 2003	Whiting Petroleum Corporation Year Ended December 31, 2003
	(in millions, except per share data)			
Consolidated Income Statement Information:				
Revenues:				
Oil and gas sales	$ 224.8	$ 166.4	$ 267.0	$ 175.8
Loss on oil and gas hedging activities	(3.6)	(3.6)	(8.7)	(8.7)
Gain on sale of oil and gas properties	1.0	1.0		
Gain on sale of marketable securities	4.7	4.7		
Interest income and other	0.2	0.2	0.3	0.3
Total revenues	$ 227.1	$ 168.7	$ 258.6	$ 167.4
Costs and expenses:				
Lease operating	$ 45.5	$ 34.6	$ 57.2	$ 43.2
Production taxes	13.6	10.2	15.9	10.7
Depreciation, depletion and amortization	48.5	34.5	67.2	41.3
Exploration and impairment	4.7	4.7	3.2	3.2
Phantom equity plan[1]			10.9	10.9
General and administrative	17.1	14.2	17.5	12.8
Interest expense	17.9	9.6	19.7	9.2
Total costs and expenses	$ 147.3	$ 107.8	191.6	$ 131.3

Income before income taxes and cumulative change in accounting principle	$ 79.8	$ 60.9	$ 67.0	$ 36.1
Income tax expense	(30.8)	(23.5)	(25.8)	(13.9)
Income from continuing operations	49.0	37.4	41.2	22.2
Cumulative change in accounting principle(2)			(3.9)	(3.9)
Net income	$ 49.0	$ 37.4	37.3	$ 18.3
Net income per common share from continuing operations, basic and diluted	$ 2.53	$ 1.93	$ 2.20	$ 1.18
Net income per common share, basic and diluted	$ 2.53	$ 1.93	$ 2.00	$ 0.98
Other Financial Information:				
EBITDA(3)	$ 146.2	$ 105.0	$ 150.0	$ 82.7

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(1) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock valued at approximately $6.5 million after withholding of shares for payroll and income taxes. As a result, in the fourth quarter of 2003, we recorded a one-time non-cash charge of $6.5 million and a one-time cash charge of $4.4 million, of which Alliant Energy Corporation funded the substantial majority. The phantom equity plan is now terminated.

(2) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. The adoption of SFAS 143 included a one-time cumulative effect adjustment to net income.

(3) We define EBITDA as earnings before interest, taxes, depreciation, depletion and amortization. EBITDA is not a measure of performance calculated in accordance with generally accepted accounting principles in the United States, or GAAP. Although not prescribed under GAAP, we believe the presentation of EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other companies that have different financing and capital structures or tax rates. EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. EBITDA, as we calculate it, may not be comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use.

The following table presents a reconciliation of net income to EBITDA:

	Pro Forma for The Nine Months Ended September 30, 2004	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Pro Forma for The Year Ended December 31, 2003	Whiting Petroleum Corporation Year Ended December 31, 2003
	(in millions)			
Net income	$ 49.0	$ 37.4	$ 37.3	$ 18.3
Income tax expense	30.8	23.5	25.8	13.9
Interest expense	17.9	9.6	19.7	9.2
Depreciation, depletion and amortization	48.5	34.5	67.2	41.3
EBITDA	$ 146.2	$ 105.0	$ 150.0	$ 82.7

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Summary Historical and Pro Forma Reserve and Operating Data

The following tables present summary information regarding our estimated net proved oil and natural gas reserves as of October 1, 2004 and as of December 31, 2003, and our historical operating data for the year ended December 31, 2003 and the nine months ended September 30, 2004. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC, and, except as otherwise indicated, give no effect to federal or state income taxes. For additional information regarding our reserves, please read Business and Properties Summary of Oil and Natural Gas Properties and Projects and note 10 to our financial statements. The summary pro forma reserve and operating data below gives effect to our recent acquisition of Permian Basin properties as if such transaction had occurred as of January 1, 2003. The summary unaudited pro forma reserve and operating data do not reflect the pro forma effect of our other recent acquisitions. Our historical operating data includes results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical operating data does not include results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our reserve data as of October 1, 2004 does include reserves from such acquisition.

	Whiting Petroleum Corporation as of October 1, 2004	Pro Forma as of December 31, 2003	Whiting Petroleum Corporation as of December 31, 2003
Reserve Data:			
Total estimated net proved reserves:			
Natural gas (Bcf)	337.9	287.6	231.0
Oil (MMbbls)	88.2	68.2	34.6
Total (Bcfe)	867.3	696.8	438.8
Estimated net proved developed reserves:			
Natural gas (Bcf)	245.8	212.7	171.9
Oil (MMbbls)	63.0	45.2	26.2
Total (Bcfe)	624.1	483.9	328.9
Estimated future net revenues before income taxes (in millions)	$ 3,908.0	$ 3,508.9	$ 1,352.2
Present value of estimated future net revenues before income taxes (in millions)(1)(2)	$ 2,087.9	$ 1,142.1	$ 784.6
Standardized measure of discounted future net cash flows (in millions)(3)	$ 1,466.2	$ 896.1	$ 589.6

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	Pro Forma for the Nine Months Ended September 30, 2004	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Pro Forma for the Year Ended December 31, 2003	Whiting Petroleum Corporation Year Ended December 31, 2003
Operating Data:				
Net Production:				
Natural gas (Bcf)	20.6	17.1	27.4	21.6
Oil (MMbbls)	3.3	2.2	4.8	2.6
Total (Bcfe)	40.1	30.0	56.1	37.2
Net sales (in millions)[4]:				
Natural gas	$ 107.4	$ 90.6	$ 130.4	$ 104.4
Oil	$ 117.4	$ 75.8	$ 136.6	$ 71.3
Total	$ 224.8	$ 166.4	$ 267.0	$ 175.7
Average sales price:				
Natural gas (per Mcf)[4]	$ 5.21	$ 5.30	$ 4.74	$ 4.78
Oil (per Bbl)[4]	$ 35.90	$ 35.13	$ 28.69	$ 27.50
Total (Mcfe)[4]	$ 5.59	$ 5.54	$ 4.76	$ 4.73
Average (per Mcfe):				
Lease operating expenses	$ 1.13	$ 1.15	$ 1.02	$ 1.16
Production taxes	$ 0.34	$ 0.34	$ 0.28	$ 0.29
Depreciation, depletion and amortization expenses	$ 1.20	$ 1.15	$ 1.20	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.42	$ 0.47	$ 0.31	$ 0.34
Net income	$ 1.22	$ 1.25	$ 0.67	$ 0.49
EBITDA[5]	$ 3.63	$ 3.49	$ 2.68	$ 2.22

(1) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, as of the calculation date, discounted at 10% per year on a pre-tax basis.

(2) The December 31, 2003 amount was calculated using a period end average realized oil price of $29.43 per barrel and a period end average realized natural gas price of $5.52 per Mcf, and the October 1, 2004 amount was calculated using a period end average realized oil price of $45.87 per barrel and a period end average realized natural gas price of $5.64 per Mcf.

(3) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10%.

(4) Before consideration of hedging transactions.

(5) See Note 3 to Summary Historical and Unaudited Pro Forma Financial Information for a definition of EBITDA and a reconciliation of EBITDA to net income for the periods presented.

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Summary Historical Financial Information

The following summary historical financial information for each of the three years ended December 31, 2003 has been derived from our audited consolidated financial statements and related notes. The summary historical financial information for the nine months ended September 30, 2004 and 2003 has been derived from our unaudited consolidated financial statements and related notes. This information is only a summary and you should read it in conjunction with material contained in Management s Discussion and Analysis of Financial Condition and Results of Operations, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our financial statements and related notes included elsewhere in this prospectus. The unaudited interim period financial information, in our opinion, includes all adjustments, which are normal and recurring in nature, necessary for a fair presentation for the periods shown. Results for the nine months ended September 30, 2004 are not necessarily indicative of the results to be expected for the full fiscal year. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include the results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our balance sheet information as of September 30, 2004 does include the effect of such acquisition.

	Nine Months Ended September 30,		Year Ended December 31,		
	2004	2003	2003	2002	2001
	(dollars in millions)				
Consolidated Income Statement Information:					
Revenues:					
Oil and gas sales	$ 166.4	$ 133.6	$ 175.8	$ 122.7	$ 125.2
Gain (loss) on oil and gas hedging activities	(3.6)	(9.0)	(8.7)	(3.2)	2.3
Gain on sale of oil and gas properties	1.0			1.0	11.7
Gain on sale of marketable securities	4.7				
Interest income and other	0.2	0.2	0.3		0.2
Total revenues	$ 168.7	$ 124.8	$ 167.4	$ 120.5	$ 139.4
Costs and expenses:					
Lease operating	$ 34.6	$ 32.1	$ 43.2	$ 32.9	$ 29.8
Production taxes	10.2	8.1	10.7	7.4	6.5
Depreciation, depletion and amortization(1)	34.5	30.7	41.3	43.6	26.9
Exploration and impairment	4.7	1.0	3.2	1.8	0.8
Phantom equity plan(2)			10.9		
General and administrative	14.2	9.5	12.8	12.0	10.9
Interest expense	9.6	7.1	9.2	10.9	10.2
Total costs and expenses	$ 107.8	$ 88.5	$ 131.3	$ 108.6	$ 85.1
Income before income taxes and cumulative change in accounting principle	$ 60.9	$ 36.3	$ 36.1	$ 11.9	$ 54.3
Income tax expense(3)	(23.5)	(13.8)	(13.9)	(4.2)	(13.1)
Income from continuing operations	37.4	22.5	22.2	7.7	41.2
Cumulative change in accounting principle(4)		(3.9)	(3.9)		
Net income	$ 37.4	$ 18.6	$ 18.3	$ 7.7	$ 41.2
Net income per common share from continuing operations, basic and diluted	$ 1.93	$ 1.20	$ 1.18	$ 0.41	$ 2.20

Net income per common share, basic and diluted	$ 1.93	$ 0.99	$ 0.98	$ 0.41	$ 2.20
Other Financial Information:					
Net cash provided by operating activities	$ 96.9	$ 75.0	$ 96.4	$ 62.6	$ 62.3
Capital expenditures(5)	$ 498.1	$ 33.1	$ 52.0	$ 165.4	$ 99.6
EBITDA(6)	$ 105.0	$ 70.2	$ 82.6	$ 66.4	$ 91.4

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	As of September 30,		As of December 31,		
	2004	2003	2003	2002	2001
	(dollars in millions)				
Balance Sheet Information:					
Cash and cash equivalents	$ 17.4	$ 42.5	$ 53.6	$ 4.8	$ 1.0
Total assets	$ 1,054.6	$ 502.5	$ 536.3	$ 448.5	$ 319.8
Long-term debt[7]	$ 538.8	$ 185.0	$ 188.0	$ 265.5	$ 163.6
Stockholders equity	$ 334.9	$ 224.9	$ 259.6	$ 122.8	$ 111.5

(1) We reduced the amount of our asset retirement obligations estimate from approximately $13.0 million at December 31, 2000 to $4.0 million at December 31, 2001 as a result of receiving a revised and more detailed dismantlement plan from our dismantlement operator. This $9.0 million change in estimate reduced our depreciation, depletion and amortization expense in our 2001 financial statements as the expense for the asset retirement obligations had originally been recorded as a depreciation, depletion and amortization expense.

(2) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock valued at approximately $6.5 million after withholding of shares for payroll and income taxes. As a result, in the fourth quarter of 2003, we recorded a one-time non-cash charge of $6.5 million and a one-time cash charge of $4.4 million, of which Alliant Energy Corporation funded the substantial majority. The phantom equity plan is now terminated.

(3) We generated Section 29 tax credits of $6.6 million in 2001 and $5.4 million in 2002. Section 29 tax credit provisions of the Internal Revenue Code expired as of December 31, 2002. In 2002, we were able to use our $5.4 million of Section 29 tax credits in the consolidated federal income tax return filed by Alliant Energy, but since these credits would not have been used in a stand-alone filing, they were recorded as additional paid-in capital as opposed to a reduction in income tax expense.

(4) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. The adoption of SFAS 143 included a one-time cumulative effect adjustment to net income.

(5) In 2003, we acquired the limited partnership interests in three partnerships in which our wholly owned subsidiary is the general partner. Though disclosed as acquisitions of limited partnership interests in our consolidated statements of cash flows, these amounts are recorded as oil and natural gas properties on our consolidated balance sheets and are included in capital expenditures in this summary historical financial information.

(6) See Note 6 to Selected Historical Financial Information for a definition of EBITDA and a reconciliation of EBITDA to net income for the periods presented.

(7) Long-term debt as of September 30, 2004 does not include $50.0 million of long-term debt classified as current.

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Summary Historical Reserve and Operating Data

The following tables present summary information regarding our estimated net proved oil and natural gas reserves as of October 1, 2004 and as of December 31, 2003, 2002 and 2001, and our historical operating data for the years ended December 31, 2003, 2002 and 2001 and the nine months ended September 30, 2004 and 2003. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC, and, except as otherwise indicated, give no effect to federal or state income taxes. For additional information regarding our reserves, please read Business and Properties Summary of Oil and Natural Gas Properties and Projects and note 10 to our financial statements. Our historical operating data includes results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical operating data does not include results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our reserve data as of October 1, 2004 does include reserves from such acquisition.

	As of October 1,	As of December 31,		
	2004	2003	2002	2001
Reserve Data:				
Total estimated net proved reserves:				
Natural gas (Bcf)	337.9	231.0	236.0	227.5
Oil (MMbbls)	88.2	34.6	29.5	14.8
Total (Bcfe)	867.3	438.8	412.7	316.3
Estimated net proved developed reserves:				
Natural gas (Bcf)	245.8	171.9	167.6	136.8
Oil (MMbbls)	63.0	26.2	23.8	11.0
Total (Bcfe)	624.1	328.9	310.4	202.8
Estimated future net revenues before income taxes (in millions)	$ 3,908.0	$ 1,352.2	$ 1,112.4	$ 425.6
Present value of estimated future net revenues before income taxes (in millions)(1)(2)	$ 2,087.9	$ 784.6	$ 638.6	$ 244.6
Standardized measure of discounted future net cash flows (in millions)(3)	$ 1,466.2	$ 589.6	$ 476.0	$ 211.7

	Nine Months Ended September 30,		Year Ended December 31,		
	2004	2003	2003	2002	2001
Operating Data:					
Net Production:					
Natural gas (Bcf)	17.1	16.1	21.6	21.4	19.8
Oil (MMbbls)	2.2	1.9	2.6	2.3	2.1
Total (Bcfe)	30.0	27.7	37.2	35.2	32.4
Net sales (in millions)(4):					
Natural gas	$ 90.6	$ 80.1	$ 104.4	$ 68.6	$ 75.4
Oil	$ 75.8	$ 53.5	$ 71.3	$ 54.1	$ 49.8
Total	$ 166.4	$ 133.6	$ 175.7	$ 122.7	$ 125.2
Average sales price:					
Natural gas (per Mcf)(4)	$ 5.30	$ 4.98	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)(4)	$ 35.13	$ 27.71	$ 27.50	$ 23.35	$ 23.85
Total (Mcfe)(4)	$ 5.54	$ 4.83	$ 4.73	$ 3.48	$ 3.88
Average (per Mcfe):					
Lease operating expenses	$ 1.15	$ 1.16	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.34	$ 0.29	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expenses(5)	$ 1.15	$ 1.11	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.47	$ 0.34	$ 0.34	$ 0.34	$ 0.34

Net income	$ 1.25	$ 0.67	$ 0.49	$ 0.22	$ 1.28
EBITDA[6]	$ 3.49	$ 2.54	$ 2.22	$ 1.88	$ 2.83

[1] The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, as of the calculation date, discounted at 10% per year on a pre-tax basis.

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(2) The December 31, 2003 amount was calculated using a period end average realized oil price of $29.43 per barrel and a period end average realized natural gas price of $5.52 per Mcf, the December 31, 2002 amount was calculated using a period end average realized oil price of $28.21 per barrel and a period end average realized natural gas price of $4.39 per Mcf, and the October 1, 2004 amount was calculated using a period end average realized oil price of $45.87 per barrel and a period end average realized natural gas price of $5.64 per Mcf.

(3) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10%.

(4) Before consideration of hedging transactions.

(5) We reduced the amount of our asset retirement obligations estimate from approximately $13.0 million at December 31, 2000 to $4.0 million at December 31, 2001 as a result of receiving a revised and more detailed dismantlement plan from our dismantlement operator. This $9.0 million change in estimate reduced our depreciation, depletion and amortization expense in our 2001 financial statements as the expense for the asset retirement obligations had originally been recorded as a depreciation, depletion and amortization expense.

(6) See Note 6 to Selected Historical Financial Information for a definition of EBITDA and a reconciliation of EBITDA to net income for the periods presented.

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RISK FACTORS

You should carefully consider each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in shares of our common stock. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected and you may lose all or part of your investment.

Risks Relating to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operation.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined in the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read Reserve estimates depend on many assumptions that may turn out to be inaccurate for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;

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- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any future acquisitions and our recently completed acquisitions described in this prospectus:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may incur additional debt related to future acquisitions.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Properties that we buy may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes a continuing acquisition program and we have acquired a substantial number of properties in 2004. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;

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- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Our leverage may impair our financial condition.

As of September 30, 2004, after giving effect to our offering of 7,500,000 shares of our common stock and the application of the proceeds of such offering to retire debt as if those transactions occurred on September 30, 2004, our total consolidated debt would have been $374.5 million. See Capitalization for additional information.

Our debt could have important consequences to you, including:

- increasing our vulnerability to general adverse economic and industry conditions;
- requiring a substantial portion of our cash flow from operations be used for the payment of interest on our debt, therefore reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions and general corporate requirements;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions and general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industries in which we operate; and

placing us at a competitive disadvantage to other less leveraged competitors.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with bank borrowings and cash generated by operations. We intend to finance our future capital expenditures with cash flow from operations and our existing financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

our proved reserves;

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- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our bank credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, then we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil reserves.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. Please read Business and Properties Summary of Oil and Natural Gas Properties and Projects for information about our oil and natural gas reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If natural gas prices decline by $0.10 per Mcf, then the pre-tax PV10% value of our proved reserves as of January 1, 2004 would decrease from $784.6 million to $773.2 million. If oil prices decline by $1.00 per barrel, then the pre-tax PV10% value of our proved reserves as of January 1, 2004 would decrease from $784.6 million to $770.0 million.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This limits our ability to

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operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this prospectus. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations, or an operator s breach of the applicable agreements, could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator s timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, some of our drilling activities may not be successful or economical and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may chose not to acquire option or lease rights prior to acquiring seismic data and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D data without having an opportunity to attempt to benefit from those expenditures.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of natural gas pipeline or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and

taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

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Our operations may incur substantial liabilities to comply with the environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities, and concentration of materials that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well as those of the oil and natural gas industry in general. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Federal law and some state laws also allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, our President and Chief Executive Officer, James R. Casperson, our Chief Financial Officer, James T. Brown, our Vice President, Operations, John R. Hazlett, our Vice President, Acquisitions and Land or Mark R. Williams, our Vice President, Exploration and Development, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income.

We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions have to date consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions. We have contracts maturing in the fourth quarter of 2004 covering the sale of 1,450,000 MMbtu of natural gas and 314,000 barrels of oil, and our amended and restated credit agreement requires us to hedge at least 60% of our total forecasted PDP production for the period from November 1, 2004 through December 31, 2005. See Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosure about Market Risk for pricing and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we would have otherwise received from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

Risks Relating to Our Common Stock

Our stock price may be volatile.

The market price of our common stock could be subject to significant fluctuations, and may decline. The following factors could affect our stock price:

- our operating and financial performance and prospects,
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues,
- changes in revenue or earnings estimates or publication of research reports by analysts,

- speculation in the press or investment community,
- general market conditions, including fluctuations in commodity prices, and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

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We have no plans to pay dividends on our common stock. You may not receive funds without selling your shares.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our certificate of incorporation and by-laws that could delay or prevent an unsolicited change in control of our company include a staggered board of directors, board authority to issue preferred stock, advance notice provisions for director nominations or business to be considered at a stockholder meeting and supermajority voting requirements. In addition, Delaware law imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. See Description of Capital Stock Preferred Stock and Description of Capital Stock Delaware Anti-Takeover Law and Charter and By-law Provisions.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains statements that we believe to be forward looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward looking statements. When used in this prospectus, words such as we expect, intend, plan, estimate, anticipate, belie should or the negative thereof or variations thereon or similar terminology are generally intended to identify forward looking statements. Such forward looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Some, but not all, of the risks and uncertainties include: declines in oil or natural gas prices; our level of success in exploitation, exploration, development and production activities; our ability to obtain external capital to finance acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses, including our ability to realize cost savings from the acquisitions we completed in 2004; unforeseen underperformance of or liabilities associated with acquired properties; inaccuracies of our reserve estimates or our assumptions underlying them; failure of our properties to yield oil or natural gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and natural gas operations; our inability to access oil and natural gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and natural gas operations; risks related to our level of indebtedness; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and natural gas industry; risks arising out of our hedging transactions; and other risks described under the caption Risk Factors . We assume no obligation, and disclaim any duty, to update the forward looking statements in this prospectus.

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USE OF PROCEEDS

We will receive net proceeds of approximately $214.3 million from our sale of 7,500,000 shares of our common stock in this offering at an assumed offering price of $29.85 per share, after deducting the underwriting discount and estimated offering expenses. If the underwriters over-allotment option is exercised in full, we will receive net proceeds of approximately $246.6 million. We will use all of the net proceeds we receive from this offering to repay debt outstanding under Whiting Oil and Gas Corporation s credit agreement that we incurred in connection with the acquisitions described under Prospectus Summary Recent Acquisitions and Business and Properties Recent Acquisitions. The credit agreement currently bears interest at the rate of 3.34% and matures in September 2008.

We will not receive any of the net proceeds from the concurrent sale of 1,080,000 shares of our common stock by Resources.

CAPITALIZATION

The following table sets forth our capitalization as of September 30, 2004 on an actual basis and as adjusted to reflect our sale of 7,500,000 shares of our common stock in this offering at an assumed offering price of $29.85 per share, after deducting the underwriting discount and estimated offering expenses, and the application of the net proceeds from this offering as described under Use of Proceeds. You should read this table in conjunction with our financial statements and the notes to those financial statements included elsewhere in this prospectus. The information below assumes the underwriters do not exercise their over-allotment option.

	September 30, 2004	
	Actual	**As Adjusted**
	(dollars in thousands)	
Cash and cash equivalents	$ 17,361	$ 17,361
Short-term debt	$ 50,000	$
Long-term debt:		
Whiting Oil and Gas Corporation credit agreement	385,000	220,655
Note payable to Alliant Energy Corporation	3,130	3,130
Senior subordinated notes(1)	150,697	150,697
Total debt	588,827	374,482
Stockholders equity:		
Common stock: $0.001 par value, 75,000,000 shares authorized, 21,100,347 shares issued and outstanding	21	29
Preferred Stock: $0.001 par value, 5,000,000 shares authorized, no shares issued or outstanding		
Additional paid-in capital	216,120	430,457
Deferred compensation	(2,035)	(2,035)
Accumulated other comprehensive loss	(6,050)	(6,050)
Retained earnings	126,841	126,841
Total stockholders equity	$ 334,897	$ 549,242
Total capitalization	$ 923,724	$ 923,724

(1) Represents \$150.0 million aggregate principal amount of 7 1/4% senior subordinated notes due 2012.

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PRICE RANGE OF COMMON STOCK AND DIVIDENDS

Our common stock has been traded on the New York Stock Exchange under the symbol WLL since our initial public offering on November 20, 2003. The following table shows the high and low sale prices for our common stock for the periods presented.

	High	Low
Fiscal Year Ended December 31, 2003		
Fourth Quarter (from November 20, 2003 through December 31, 2003)	$ 18.54	$ 16.15
Fiscal Year Ended December 31, 2004		
First Quarter (Ended March 31, 2004)	$ 23.94	$ 18.45
Second Quarter (Ended June 30, 2004)	$ 27.59	$ 21.50
Third Quarter (Ended September 30, 2004)	$ 31.20	$ 21.85
Fourth Quarter (Through November 3, 2004)	$ 34.22	$ 29.00

On November 3, 2004, the last sale price of our common stock as reported on the New York Stock Exchange was $29.85.

As of October 14, 2004, there were 996 stockholders of record and approximately 16,000 beneficial owners of our common stock.

We have not paid any dividends since we were incorporated in July 2003. We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

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UNAUDITED PRO FORMA FINANCIAL STATEMENTS

On September 23, 2004, we completed our acquisition of interests in seventeen oil and natural gas fields located in the Permian Basin of West Texas and Southeast New Mexico, which we refer to as the Permian Basin Acquisition Properties, from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. and Baytech, L.L.P. The effective date of the purchase was July 1, 2004. The cash purchase price was $345.0 million, subject to closing adjustments.

The following unaudited pro forma financial information shows the pro forma effect of the acquisition of the Permian Basin Acquisition Properties. It does not reflect the pro forma effect of any of our other recent acquisitions discussed in this prospectus. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include results from our Wyoming and Utah acquisition that closed on September 30, 2004. A pro forma balance sheet has not been presented since the acquisition has been reflected in the September 30, 2004 balance sheet of Whiting Petroleum Corporation included elsewhere in this prospectus. The unaudited pro forma statement of operations for the nine months ended September 30, 2004 and for the year ended December 31, 2003 was prepared as if the acquisition had occurred at January 1, 2003.

The accompanying statements of revenues and direct operating expenses for the Permian Basin Acquisition Properties were derived from the historical accounting records of the sellers and prior operators. Although the statements do not include depreciation, depletion and amortization, general administrative expenses, income taxes or interest expense, as described in Notes 2 and 3, these costs have been included on a pro forma basis. The pro forma financial information also includes the effects of our bank credit agreement, which was amended concurrent with the property acquisition. The terms of the amendment increased the credit agreement to $750 million with a $480 million borrowing base. After the closing of this acquisition, we had $400 million of outstanding borrowings under the facility.

We believe that the assumptions used provide a reasonable basis for presenting the significant effects directly attributable to such transactions.

The following unaudited pro forma financial statements do not purport to represent what our results of operations would have been if this acquisition had occurred on January 1, 2003. These unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented included in this prospectus.

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UNAUDITED CONDENSED PRO FORMA STATEMENT OF OPERATIONS FOR

THE NINE MONTHS ENDED SEPTEMBER 30, 2004 (in millions, except per share data)

	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Permian Basin Acquisition Properties Six Months Ended June 30, 2004	Pro Forma Adjustments (Note 2)	Pro Forma Combined September 30, 2004
REVENUES				
Oil and gas sales	$ 166.4	$ 39.1	$ 19.3	$ 224.8
Loss on oil and gas hedging activities	(3.6)			(3.6)
Gain on sale of marketable securities	4.7			4.7
Gain on sale of oil and gas properties	1.0			1.0
Interest income and other	0.2			0.2
Total revenues	168.7	39.1	19.3	227.1
COSTS AND EXPENSES:				
Lease operating	34.6	8.3	2.6	45.5
Production taxes	10.2	2.3	1.1	13.6
Depreciation, depletion and amortization	34.5		14.0	48.5
Exploration and impairment	4.7			4.7
General and administrative	14.2		2.9	17.1
Interest expense	9.6		8.3	17.9
Total costs and expenses	$ 107.8	10.6	28.9	147.3
INCOME BEFORE INCOME TAXES	60.9	$ 28.5	(9.6)	79.8
INCOME TAX EXPENSE:				
Current	(0.4)			(0.4)
Deferred	(23.1)		(7.3)	(30.4)
Total income tax expenses	(23.5)		(7.3)	(30.8)
NET INCOME	$ 37.4		$ (16.9)	$ 49.0
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 1.93			$ 2.53
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	19,341			19,341

WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	19,370	19,370

See accompanying notes to pro forma statements of operations.

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UNAUDITED CONDENSED PRO FORMA STATEMENT OF OPERATIONS FOR

THE YEAR ENDED DECEMBER 31, 2003 (in millions, except per share data)

	Whiting Petroleum Corporation Year Ended December 31, 2003	Permian Basin Acquisition Properties Year Ended December 31, 2003	Pro Forma Adjustments (Note 2)	Pro Forma Combined December 31, 2003
REVENUES				
Oil and gas sales	$ 175.8	$ 91.2	$	$ 267.0
Loss on oil and gas hedging activities	(8.7)			(8.7)
Interest income and other	0.3			0.3
Total revenues	167.4	91.2		258.6
COSTS AND EXPENSES:				
Lease operating	43.2	14.0		57.2
Production taxes	10.7	5.2		15.9
Depreciation, depletion and amortization	41.3		25.9	67.2
Exploration	3.2			3.2
General and administrative	12.8		4.7	17.5
Phantom equity plan	10.9			10.9
Interest expense	9.2		10.5	19.7
Total costs and expenses	131.3	19.2	41.1	191.6
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	36.1	$ 72.0	(41.1)	67.0
INCOME TAX EXPENSE:				
Current	(2.4)			(2.4)
Deferred	(11.5)		(11.9)	(23.4)
Total income tax expense	(13.9)		(11.9)	(25.8)
INCOME FROM CONTINUING OPERATIONS	22.2		(53.0)	41.2
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3.9)			(3.9)
NET INCOME	$ 18.3		$ (53.0)	$ 37.3
Earnings per share from continuing operations, basic and diluted	$ 1.18			$ 2.20
Cumulative change in accounting principle	(0.20)			(0.20)
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.98			$ 2.00

WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC AND DILUTED	18,750	18,750

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NOTES TO THE UNAUDITED PRO FORMA STATEMENTS OF OPERATIONS

1. BASIS OF PRESENTATION

On September 23, 2004, we completed our acquisition of interests in seventeen oil and natural gas fields located in the Permian Basin of West Texas and Southeast New Mexico (the Permian Basin Acquisition Properties) from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. and Baytech, L.L.P. The effective date of the purchase was July 1, 2004. The cash purchase price was $345 million subject to closing adjustments.

The following unaudited pro forma financial information shows the pro forma effect of the acquisition of the Permian Basin Acquisition Properties. It does not reflect the pro forma effect of any of our other recent acquisitions discussed in this prospectus. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include results from our Wyoming and Utah acquisition that closed on September 30, 2004. A pro forma balance sheet has not been presented since the acquisition has been reflected in our September 30, 2004 balance sheet of Whiting Petroleum Corporation, located elsewhere in this prospectus. The unaudited pro forma statement of operations for the nine months ended September 30, 2004 and for the year ended December 31, 2003 was prepared as if the acquisition had occurred at January 1, 2003.

The accompanying statements of revenues and direct operating expenses for the Permian Basin Acquisition Properties were derived from the historical accounting records of the sellers and prior operators. Although the statements do not include depreciation, depletion and amortization, general administrative expenses, income taxes or interest expense, as described in Notes 2 and 3, these costs have been included on a pro forma basis. The pro forma financial information also includes the effects of our bank credit agreement which was amended concurrent with the property acquisition. The terms of the amendment increased the credit facility to $750 million with a $480 million borrowing base. After the closing of this acquisition, the Company had $400 million of outstanding borrowings under the facility.

We believe that assumptions used provide a reasonable basis for presenting the significant effects directly attributable to such transactions.

The following unaudited pro forma financial statements do not purport to represent what our results of operations would have been if this acquisition had occurred on January 1, 2003. These unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented.

Earnings Per Share Basic net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding during each period. Diluted net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding and other dilutive securities. The only securities considered dilutive are our unvested restricted stock awards. The dilutive effect of these securities were immaterial to the calculation.

2. PRO FORMA ADJUSTMENTS FOR NINE MONTHS ENDED SEPTEMBER 30, 2004

The accompanying unaudited condensed pro forma statement of operations for the nine months ended September 30, 2004 assumes the acquisition of the Permian Basin Acquisition Properties occurred as of January 1, 2003. The following adjustments have been made to the accompanying condensed pro forma statement of operations for the nine months ended September 30, 2004:

Revenues, Lease Operating and Production Taxes To adjust for the period from July 1, 2004 to the closing date of September 23, 2004.

Depletion, Depreciation and Amortization To record pro forma depletion expense giving effect to the acquisition of the Permian Basin Acquisition Properties. The expense was calculated using estimated proved reserves by field and the preliminary $345.0 million purchase price allocation. None of the purchase price was allocated to unproved properties.

General and Administrative To record expenses associated with anticipated increases in personnel and office expansion. This adjustment also includes the estimated costs related to our production participation plan for the periods indicated. Under our production participation plan for the 2004 plan year, the estimated discounted value of the plan must be expensed immediately for employees over 65 years old and amortized over five years for the majority of other employees.

Interest Expense To record interest expense for additional debt and debt issuance costs incurred in connection with the Permian Basin Acquisition Properties. We used historical rates paid during the nine months ended September 30, 2004 which approximated 3.2%. Each 1/8% change in the interest rate would affect net income before income taxes by $295,000 for the nine month period.

Income Taxes To record income related to the pretax income from the Permian Basin Acquisition Properties for the period from January 1, 2004 to the closing date of September 23, 2004, based on our effective tax rate of 38.6%.

3. PRO FORMA ADJUSTMENTS FOR YEAR ENDED DECEMBER 31, 2003

The accompanying unaudited pro forma statement of operations for the year ended December 31, 2003 assumes the acquisition of the Permian Basin Acquisition Properties occurred as of January 1, 2003. The following adjustments have been made to the accompanying pro forma statement of operations for the year ended December 31, 2003:

Depletion, Depreciation and Amortization To record pro forma depletion expense giving effect to the acquisition of the Permian Basin Acquisition Properties. The expense was calculated using estimated proved reserves by field and the preliminary $345.0 million purchase price allocation.

General and Administrative To record expenses associated with anticipated increases in personnel and office expansion. This adjustment also includes the estimated costs related to our production participation plan for the periods indicated. Under our production participation plan, for the 2004 plan year, the estimated discounted value to the plan must be expensed immediately for employees over 65 years old and amortized over five years for the majority of other employees.

Interest Expense To record interest expense for additional debt and debt issuance costs incurred in connection with the Permian Basin Acquisition Properties. We used historical rates paid during the year ended December 31, 2003 which approximated 3.0%. Each 1/8% change in the interest rate would affect net income before income taxes by $394,000 for the year.

Income Taxes To record income related to the pretax income from the Permian Basin Acquisition Properties for the year ended December 31, 2003, based on our effective tax rate of 38.6%.

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SELECTED HISTORICAL FINANCIAL INFORMATION

The following selected historical financial information for each of the four years ended December 31, 2003, has been derived from our audited consolidated financial statements and related notes. The following selected historical financial information for the nine months ended September 30, 2004 and 2003 and the year ended December 31, 1999 and the balance sheet information as of December 31, 2000 and 1999 has been derived from our unaudited consolidated financial statements. This information is only a summary and you should read it in conjunction with material contained in the section entitled Management s Discussion and Analysis of Financial Condition and Results of Operations, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our financial statements and related notes included elsewhere in this prospectus. The unaudited interim period financial information, in our opinion, includes all adjustments, which are normal and recurring in nature, necessary for a fair presentation of the periods shown. Results for the nine months ended September 30, 2004 are not necessarily indicative of the results to be expected for the full fiscal year. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include the results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our balance sheet information as of September 30, 2004 does include the effect of such acquisition.

	Nine Months Ended September 30,		Year Ended December 31,				
	2004	**2003**	**2003**	**2002**	**2001**	**2000**	**1999**
	(dollars in millions, except per share data)						
Consolidated Income Statement Information:							
Revenues:							
Oil and gas sales	$ 166.4	$ 133.6	$ 175.8	$ 122.7	$ 125.2	$ 107.0	$ 60.9
Gain (loss) on oil and gas hedging activities	(3.6)	(9.0)	(8.7)	(3.2)	2.3	(3.8)	
Gain on sale of oil and gas properties	1.0			1.0	11.7	7.7	10.1
Gain on sale of marketable securities	4.7						
Interest income and other	0.2	0.2	0.3		0.2	0.1	0.1
Total revenues	$ 168.7	$ 124.8	$ 167.4	$ 120.5	$ 139.4	$ 111.0	$ 71.1
Costs and expenses:							
Lease operating	$ 34.6	$ 32.1	$ 43.2	$ 32.9	$ 29.8	$ 23.8	$ 20.7
Production taxes	10.2	8.1	10.7	7.4	6.5	5.4	3.0
Depreciation, depletion and amortization(1)	34.5	30.7	41.3	43.6	26.9	21.5	19.8
Exploration and impairment	4.7	1.0	3.2	1.8	0.8	1.1	5.2
Phantom equity plan(2)			10.9				
General and administrative	14.2	9.5	12.8	12.0	10.9	6.3	4.3
Interest expense	9.6	7.1	9.2	10.9	10.2	7.5	5.4
Total costs and expenses	$ 107.8	$ 88.5	$ 131.3	$ 108.6	$ 85.1	$ 65.6	$ 58.4
Income before income taxes and cumulative change in accounting principle	$ 60.9	$ 36.3	$ 36.1	$ 11.9	$ 54.3	$ 45.4	$ 12.7
Income tax expense(3)	(23.5)	(13.8)	(13.9)	(4.2)	(13.1)	(11.7)	(1.8)
Income from continuing operations	37.4	22.5	22.2	7.7	41.2	33.7	10.9

Cumulative change in accounting principle[4]		(3.9)	(3.9)				
Net income	$ 37.4	$ 18.6	$ 18.3	$ 7.7	$ 41.2	$ 33.7	$ 10.9
Net income per common share from continuing operations, basic and diluted	$ 1.93	$ 1.20	$ 1.18	$ 0.41	$ 2.20	$ 1.80	$ 0.58
Net income per common share, basic and diluted	$ 1.93	$ 0.99	$ 0.98	$ 0.41	$ 2.20	$ 1.80	$ 0.58
Other Financial Information:							
Net cash provided by operating activities	$ 96.9	$ 75.0	$ 96.4	$ 62.6	$ 62.3	$ 42.3	$ 38.7
Capital expenditures[5]	$ 498.1	$ 33.1	$ 52.0	$ 165.4	$ 99.6	$ 139.1	$ 34.9
EBITDA[6]	$ 105.0	$ 70.2	$ 82.6	$ 66.4	$ 91.4	$ 74.4	$ 37.9

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	As of September 30,		As of December 31,				
	2004	2003	2003	2002	2001	2000	1999
	(dollars in millions)						
Balance Sheet Information:							
Total assets	$ 1,054.6	$ 502.5	$ 536.3	$ 448.5	$ 319.8	$ 256.4	$ 148.5
Long-term debt[7]	$ 538.8	$ 185.0	$ 188.0	$ 265.5	$ 163.6	$ 139.7	$ 72.5
Stockholder s equity	$ 334.9	$ 224.9	$ 259.6	$ 122.8	$ 111.5	$ 70.0	$ 36.2

(1) We reduced the amount of our asset retirement obligations estimate from approximately $13.0 million at December 31, 2000 to $4.0 million at December 31, 2001 as a result of receiving a revised and more detailed dismantlement plan from our dismantlement operator. This $9.0 million change in estimate reduced our depreciation, depletion and amortization expense in our 2001 financial statements as the expense for the asset retirement obligations had originally been recorded as a depreciation, depletion and amortization expense.

(2) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock valued at approximately $6.5 million after withholding of shares for payroll and income taxes. As a result, in the fourth quarter of 2003, we recorded a one-time non-cash charge of $6.5 million and a one-time cash charge of $4.4 million, of which Alliant Energy Corporation funded the substantial majority. The phantom equity plan is now terminated.

(3) We generated Section 29 tax credits of $3.0 million in 1999, $5.2 million in 2000, $6.6 million in 2001 and $5.4 million in 2002. Section 29 tax credit provisions of the Internal Revenue Code expired as of December 31, 2002. In 2002, we were able to use our $5.4 million of Section 29 tax credits in the consolidated federal income tax return filed by Alliant Energy, but since these credits would not have been used in a stand-alone filing, they were recorded as additional paid-in capital as opposed to a reduction in income tax expense.

(4) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. The adoption of SFAS 143 included a one-time cumulative effect adjustment to net income.

(5) In 2003, we acquired the limited partnership interests in three partnerships in which our wholly owned subsidiary is the general partner. Though disclosed as acquisitions of limited partnership interests in our consolidated statements of cash flows, these amounts are recorded as oil and natural gas properties on our consolidated balance sheets and are included in capital expenditures in this selected historical financial information.

(6) We define EBITDA as earnings before interest, taxes, depreciation, depletion and amortization. EBITDA is not a measure of performance calculated in accordance with generally accepted accounting principles in the United States, or GAAP. Although not prescribed under GAAP, we believe the presentation of EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other companies that have different financing and capital structures or tax rates. EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. EBITDA, as we calculate it, may not be comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use.

The following table presents a reconciliation of our consolidated net income to our consolidated EBITDA:

	Nine Months	Year Ended December 31,

	Ended September 30,						
	2004	2003	2003	2002	2001	2000	1999
Net income	$ 37.4	$ 18.6	$ 18.3	$ 7.7	$ 41.2	$ 33.7	$ 10.9
Income tax expense	23.5	13.8	13.9	4.2	13.1	11.7	1.8
Interest expense	9.6	7.1	9.2	10.9	10.2	7.5	5.4
Depreciation, depletion and amortization	34.5	30.7	41.2	43.6	26.9	21.5	19.8
EBITDA	$ 105.0	$ 70.2	$ 82.6	$ 66.4	$ 91.4	$ 74.4	$ 37.9

(7) Long-term debt as of September 30, 2004 does not include $50.0 million of long-term debt classified as current.

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MANAGEMENT S DISCUSSION AND

ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion and analysis should be read in conjunction with our selected historical financial data and our accompanying financial statements and the notes to those financial statements included elsewhere in this prospectus. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this prospectus, particularly in Risk Factors.

Overview

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California regions of the United States. Over the last four years, we have emphasized the acquisition of properties that provided current production and significant upside potential through further development. Our drilling activity is directed at this development, specifically on projects that we believe provide repeatable successes in particular fields.

Our combination of acquisitions and development allows us to direct our capital resources to what we believe to be the most advantageous investments. During periods of radically changing prices, we focus our emphasis on drilling and development of our owned properties. When prices stabilize, we generally direct the majority of our capital to acquisitions.

We have historically acquired operated as well as non-operated properties that meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis. We sell properties when management is of the opinion that the sale price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

We completed five separate acquisitions of producing properties during the first nine months of 2004. The combined purchase price for these five acquisitions was $516.1 million for total estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe. For more information on these acquisitions, see Business and Properties Recent Acquisitions. Because of our substantial recent acquisition activity, our discussion and analysis of our historical financial condition and results of operations for the periods discussed below may not necessarily be comparable with or applicable to our future results of operations. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include the results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our balance sheet information as of September 30, 2004 does include the effect of such acquisition. See Unaudited Pro Forma Financial Statements for more information about how our historical results of operations would have been affected had our acquisition of the Permian Basin properties been completed on January 1, 2003.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural

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gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	Nine Months Ended September 30,		Years Ended December 31,		
	2004	**2003**	**2003**	**2002**	**2001**
Net production:					
Natural gas (Bcf)	17.1	16.1	21.6	21.4	19.8
Oil (MMbbls)	2.2	1.9	2.6	2.3	2.1
Net sales (in millions):					
Natural gas[(1)]	$ 90.6	$ 80.1	$ 104.4	$ 68.6	$ 75.4
Oil[(1)]	$ 75.8	$ 53.5	$ 71.3	$ 54.1	$ 49.8
Average sales price:					
Natural gas (per Mcf)[(1)]	$ 5.30	$ 4.98	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)[(1)]	$ 35.13	$ 27.71	$ 27.50	$ 23.35	$ 23.85
Costs and expenses (per Mcfe):					
Lease operating expenses	$ 1.15	$ 1.16	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.34	$ 0.29	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expense	$ 1.15	$ 1.11	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.47	$ 0.34	$ 0.34	$ 0.34	$ 0.34

(1) Before consideration of hedging transactions.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased approximately $32.8 million to $166.4 million for the first nine months of 2004. Sales are a function of sales volumes and average sales prices. Our sales volumes increased 8.6% between periods on a Mcfe basis. The volume increase resulted from successful drilling and acquisition activities over the past year that produced new sales volumes that more than offset natural decline. Our average price for natural gas sales increased 6.4% and our average price for crude oil increased 26.8% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 22% of our natural gas volumes during the first nine months of 2004 incurring no hedging loss or gain, and 42% of our natural gas volumes during the same period of 2003 incurring a hedging loss of $8.0 million. We hedged 42% of our oil volumes during the first nine months of 2004 incurring a hedging loss of $3.6 million, and 11% of our oil volumes during the same period of 2003 incurring a loss of $1.0 million. See Qualitative and Quantitative Disclosures About Market Risk for a list of our outstanding oil and natural gas hedges as of October 14, 2004.

Gain on Sale of Marketable Securities. During the initial nine months of 2004, we sold all of our holdings in Delta Petroleum, Inc., which trades publicly under the symbol DPTR . We realized gross proceeds of $5.4 million and recognized a gain on sale of $4.8 million. At September 30, 2004, we had no investments in marketable securities.

Gain on Sale of Oil and Gas Properties. During the third quarter of 2004, we sold certain undeveloped acreage held by production in Wyoming. No value had been assigned to the acreage when we acquired it over five years ago. As a result, the recognized gain on sale is equal to the gross proceeds of $1.0 million.

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Lease Operating Expenses. Our lease operating expenses per Mcfe decreased from $1.16 during the first nine months of 2003 to $1.15 during the same period in 2004. The decrease was less than 1%, which represented improved operating efficiency more than offsetting price inflation caused by increased demand for goods and services in the industry.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in the various taxing jurisdictions. Due to our broad asset base, we expect our production tax rate to vary between 6.0% to 6.5% of oil and natural gas sales revenue. Our production taxes for the initial nine months of 2004 and 2003 were 6.1% of oil and natural gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) increased $3.8 million to $34.5 million for the first nine months of 2004. The increase resulted from increased production and an increase in the DD&A rate. On a Mcfe basis, the rate increased from $1.11 during the first nine months of 2003 to $1.15 during the same period in 2004. We expect our DD&A rate to increase in the fourth quarter due to the effects of the recent acquisitions. Changes to the pricing environment can also impact our DD&A rate. Price increases allow for longer economic production lives and corresponding increased reserve volumes and, as a result, lower depletion rates. Price decreases have the opposite effect. The components of our depreciation, depletion and amortization expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2004	**2003**
Depletion	$ 32,736	$ 29,011
Depreciation	550	560
Accretion of asset retirement obligations	1,214	1,104
Total	$ 34,500	$ 30,675

Exploration and Impairment Costs. Our exploration and impairment costs increased $3.7 million to $4.7 million for the first nine months of 2004. The higher exploratory costs were related to our increased purchases of seismic in 2004 to support our increased drilling budget. The impairment charge represents the write down of cost associated with the High Island field located off the coast of Texas.

	Nine Months Ended September 30,	
	2004	**2003**
Exploration	$ 2,534	$ 1,015
Impairment	2,152	
Total	$ 4,686	$ 1,015

General and Administrative Expenses. We report general and administrative expense net of reimbursements. The components of our general and administrative expense were as follows:

	Nine Months Ended September 30,	
	2004	**2003**
General and administrative expenses	$ 18,016	$ 13,806
Reimbursements	(3,825)	(4,284)
General and administrative expense, net	$ 14,191	$ 9,522

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General and administrative expense before reimbursements increased $4.2 million to $18.0 million during the first nine months of 2004. On a Mcfe basis, the increase between nine month periods was from $0.34 to $0.47. The largest component of the increase related to costs associated with our production payment plan. During periods of increased acquisition activity, our general and administrative expense will be higher because we must immediately recognize the discounted value of estimated plan payments to employees 65 and older. The discounted value of estimated payments to employees under 65 is generally amortized over a five year vesting period. Costs related to the production payment plan increased $1.8 million between nine month periods. The remaining increase was primarily caused by the extra costs of functioning as a public company, increases in the employee base due to our continued growth and general cost inflation. The decrease in reimbursements was caused by our purchase of the limited partnership interests in three of the six remaining managed partnerships during the second quarter of 2003. We expect our general and administrative expense to decrease to under $0.38 per Mcfe sold in the fourth quarter due to cost synergies from recent acquisitions.

Interest Expense. The components of our interest expense were as follows:

	Nine Months Ended September 30,	
	2004	**2003**
7 1/4% Senior Subordinated Notes due 2012	$ 3,875	$
Credit Facility	2,778	5,043
Alliant	113	1,207
Amortization of debt issue costs and debt discount	1,025	860
Accretion of tax sharing liability	1,800	
Total interest expense	$ 9,591	$ 7,110

The decrease in bank interest was primarily due to our $40.0 million pay down of our credit facility on February 17, 2004 and our repayment of the remaining principal balance outstanding under the credit facility on May 11, 2004 with the proceeds from the issuance of our 7 1/4% Senior Subordinated Notes due 2012. We expect our overall interest expense to increase during the remainder of 2004 due to the cash acquisitions closed during the third quarter of 2004, which increased the outstanding balance under our credit facility to $435 million as of September 30, 2004. In addition, in August, we entered into an interest rate swap causing the interest rate on $75 million of the 7 1/4% Senior Subordinated Notes due 2012 to change from a 7.25% fixed rate to a floating rate. The effect of the swap was to lower our overall effective interest rate on this debt from 7.25% to approximately 5.6% through November 1, 2004. On November 1, 2004 and every six months thereafter, the floating rate component will be locked in for six month periods at the then in effect six month London Interbank Offered Rate, or LIBOR, rate plus a margin of 2.345%. The decrease in interest expense related to Alliant was due to the March 31, 2003 conversion of $80.9 million of intercompany debt into our equity. The accretion of our tax sharing liability is related to a step-up in tax basis effected immediately prior to our initial public offering (IPO) in November 2003. A further explanation of the step-up transaction is included in the Liquidity and Capital Resources section below.

Income Tax Expense. We estimate that our effective income tax rate was 38.6% during the initial nine months of 2004, consistent with the yearly estimated effective tax rate for 2003. Prior to our IPO, we were included in the consolidated federal income tax return of Alliant Energy and calculated our income tax expense on a separate return basis at Alliant Energy s effective income tax rate. Immediately prior to our IPO, Alliant Energy effected a step-up in the tax basis of Whiting Oil and Gas Corporation s assets, which had the result of increasing our future tax deductions. As a result of this step-up in tax basis and the net operating loss generated during the post-IPO stub period in 2003, we currently expect to pay only a small amount of income taxes related to the 2004 tax year.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations

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associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated useful lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and the discount is accreted at the end of each accounting period through charges to D,D&A. Upon adoption of SFAS No. 143, we recorded an increase to our discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

Net Income. Net income increased from $18.6 million during the initial nine months of 2003 to $37.4 million during the same period in 2004. The primary reasons for this increase included 20% higher crude oil and natural gas prices net of hedging between periods, 8.6% increase in equivalent volumes sold, the impact of the cumulative effect of adoption of SFAS No. 143 in 2003, the impact of property and marketable security sales in 2004, offset by higher lease operating expense, general and administrative, DD&A, interest and exploration and impairment costs in 2004.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Oil and Natural Gas Sales. Oil and natural gas sales revenue increased approximately $53.0 million to $175.7 million in 2003. Natural gas sales increased $35.8 million and oil sales increased $17.2 million. The natural gas sales increase was caused by a 49% increase in the average realized natural gas price from $3.21 per Mcf in 2002 to $4.78 per Mcf in 2003 combined with a 230,000 Mcf volume increase in natural gas sales between years. The oil sales increase was caused by a sales volume increase of 275,000 Bbls in 2003 and an 18% increase in the average realized oil price from $23.35 in 2002 to $27.50 in 2003. The volume increase for oil and natural gas primarily resulted from the $217 million of capital expenditures during 2002 and 2003.

Loss on Oil and Natural Gas Hedging Activities. We hedged 41% of our natural gas volumes during 2003, incurring a hedging loss of $7.7 million, and 8% of our natural gas volumes during 2002, incurring a loss of $0.2 million. We hedged 8% of our oil volumes during 2003, incurring a hedging loss of $1.0 million, and 35% of our oil volumes during 2002, incurring a loss of $3.0 million.

Gain on Sale of Oil and Natural Gas Properties. In 2002, we divested one property, realizing a gain of $1.0 million. No significant properties were sold in 2003.

Lease Operating Expenses. Our lease operating expenses per Mcfe increased from $0.93 in 2002 to $1.16 in 2003. The increase resulted from acquisitions during 2002 that caused a larger portion of our operations to be located in Michigan and North Dakota, where weather conditions, sulfur content and remote locations create higher operating costs in comparison to other areas of operation.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 6.1% in 2003 and 6.0% in 2002. The small increase in the effective rate resulted from additional property purchases in the states of North Dakota and Montana, where effective production tax rates are higher on average than other areas where we own significant producing properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased by $2.3 million in 2003. The decrease was a result of a decrease in the average rate from $1.24 per Mcfe in 2002 to $1.11 per Mcfe in 2003, partially offset by increased sales volumes in 2003. The lower rate was a result of higher prices between periods, which allowed for a longer economic production life and corresponding increased reserve volumes and, as a result, a lower depreciation, depletion and amortization rate.

Exploration Costs. Exploration costs increased $1.4 million to $3.2 million for 2003. The increase was the result of recording three exploratory dry holes during 2003 compared to one exploratory dry hole in 2002.

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General and Administrative Expenses. General and administrative expenses increased 6.9%, or $0.8 million, to $12.8 million in 2003. This increase was related to increases in compensation expense associated with increased personnel required to administer our growth and to general cost inflation.

Phantom Equity Plan Compensation. The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan. Under this plan, our employees received compensation of $10.9 million in the form of 420,000 shares of our common stock after withholding of shares by us for estimated payroll and income taxes. The phantom equity plan is now terminated.

Interest Expense. Interest expense decreased $1.7 million to $9.2 million in 2003 compared to $10.9 million in 2002. The decrease was due to lower average debt levels in 2003 and lower effective interest rates in 2003. The lower debt levels were primarily related to a March 2003 decision by Alliant Energy to convert its remaining $80.9 million of intercompany debt into our equity thereby lowering our future interest expense.

Income Tax Expense. Our effective tax rate was 38.6% in 2003 and 35.3% during 2002. The increased effective tax rate was in part due to our 2002 acquisitions in the state of North Dakota where the effective state income tax rate is higher on average than other areas where we own significant producing properties. In addition, during 2002 we generated $5.4 million of Section 29 credits that we were not able to offset against tax expense. Under our tax separation and indemnification agreement with Alliant Energy, we expect to be compensated for these credits in the future when they are utilized by Alliant Energy. Under generally accepted accounting principles, the recording of the tax credits in 2002 were required to be charged as additional paid-in capital rather than as a decrease to our 2002 income tax expense. Section 29 tax credit provisions of the Internal Revenue Code expired December 31, 2002. Therefore, unless additional legislation is passed, Section 29 credits will not be available in periods subsequent to 2002.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated useful lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

Net Income. Net income increased from $7.7 million in 2002 to $18.3 million in 2003. The primary reasons for this increase included higher crude oil and natural gas prices between periods and higher volumes sold, offset by higher lease operating, tax and general and administrative costs due to our growth.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Oil and Natural Gas Sales. Oil and natural gas sales revenue decreased approximately $2.6 million to $122.7 million in 2002. Natural gas sales decreased $6.8 million, while oil sales increased $4.2 million. The natural gas sales decrease was caused by a 16% decline in the average realized natural gas price from $3.82 Mcf in 2001 to $3.21 Mcf in 2002, partially offset by an increase in natural gas production of 1.6 Bcf in

2002. The oil sales increase was caused by a sales volume increase of 200,000 Bbls in 2002, partially offset by a 2% decline in the average realized oil price from $23.85 in 2001 to $23.35 in 2002. The volume increase for oil and natural gas was due to $265 million of capital expenditures during 2001 and 2002.

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Loss on Oil and Natural Gas Hedging Activities. We hedged 8% of our natural gas volumes during 2002, incurring a hedging loss of $0.2 million, and 11% of our natural gas volumes during 2001, incurring a gain of $1.6 million. We hedged 35% of our oil volumes during 2002, incurring a hedging loss of $3.0 million, and 17% of our oil volumes during 2001, incurring a gain of $0.7 million.

Gain on Sale of Oil and Natural Gas Properties. In 2002, we divested only one property, realizing a gain of $1.0 million, while in 2001, we divested several properties, realizing total sales gains of $11.7 million.

Lease Operating Expenses. Our lease operating expenses per Mcfe increased from $0.92 in 2001 to $0.93 in 2002. The increase resulted from acquisitions during 2002 that caused a larger portion of our operations to be located in Michigan and North Dakota, where weather conditions, sulfur content and remote locations create higher operating costs.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 6.0% in 2002 and 5.2% in 2001. The increase in the effective rate resulted from additional property purchases in the states of North Dakota and Montana, where effective production tax rates are higher on average than other areas where we own significant producing properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense in 2001 included a $9.0 million reduction related to the asset retirement obligations for the Point Arguello platform located offshore from California. During 2001, we received a revised and more detailed dismantlement plan from the operator. The $9.0 million reduction of liability was credited against depreciation, depletion and amortization expense since the liability was initially created by charges to depreciation, depletion and amortization expense. Without this credit, our depreciation, depletion and amortization expense charge for 2001 would have been $35.9 million. The increase to $43.6 million of depreciation, depletion and amortization expense in 2002 was a result of increasing sales volumes and an increased rate from $1.11 per Mcfe in 2001 to $1.24 per Mcfe in 2002.

Exploration Costs. Exploration costs increased $1.0 million to $1.8 million for 2002 compared with $0.8 million for 2001. The increase was partially the result of a $420,000 charge for an exploratory dry hole in 2002. The remaining increase in 2002 is related to the further development and processing of our geophysical library.

General and Administrative Expenses. General and administrative expenses increased 9.5% or $1.1 million from $10.9 million in 2001 to $12.0 million in 2002. This increase was related to increases in compensation expense associated with increased personnel required to administer our growth and to general cost inflation.

Interest Expense. Interest expense increased $0.7 million to $10.9 million in 2002 compared to $10.2 million in 2001. The increase was due to higher average debt levels in 2002 to fund our growth, partially offset by a lower effective interest rate.

Income Tax Expense. Our effective tax rate before tax credits was 36.8% in 2002 and 36.2% in 2001. In 2001, we were able to reduce our tax expense by $6.6 million due to the recording of Section 29 tax credits. In 2002, we generated $5.4 million of Section 29 credits that we were not able to offset against tax expense. Under our tax separation and indemnification agreement with Alliant Energy, we expect to be compensated for these credits in the future when they are utilized by Alliant Energy. Under generally accepted accounting principles, the recording of the tax credits in 2002 were required to be charged as additional paid-in capital rather than as a decrease to our 2002 income tax expense. Section 29 tax credit provisions of the Internal Revenue Code expired December 31, 2002. Therefore, unless additional legislation is passed, Section 29 credits will not be available in periods subsequent to 2002.

Net Income. Net income decreased from $41.2 million in 2001 to $7.7 million in 2002. The primary reasons were a $19.0 million decline in revenues, a $23.5 million increase in expenses and the inability to recognize $5.4 million of tax credits as a reduction of tax expense. The revenue decrease was caused by a decline in oil and

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natural gas prices between years and $10.7 million less gains from the sales of properties in 2002. The expense increase was caused by the $9.0 million reduction to 2001 depreciation, depletion and amortization related to the adjustment of the Point Arguello asset retirement obligations and cost increases in all other categories to operate and administer the property acquisitions during 2001 and 2002.

Liquidity and Capital Resources

Overview. We entered 2004 with $53.6 million of cash and cash equivalents. During the first nine months of 2004, we generated an additional $96.9 million from operating activities. On February 17, 2004, we used $40.0 million of our cash to pay down $40.0 million of the outstanding principal balance under our bank credit facility. On May 11, 2004, we used the proceeds from the issuance of our 7 1/4% Senior Subordinated Notes due 2012 to repay the remaining $145 million of outstanding principal under our credit facility. At September 30, 2004, our debt to total capitalization ratio was 63.7%, we had $17.4 million of cash on hand and $334.9 million of stockholders equity.

We continually evaluate our capital needs and compare them to our capital resources. Our budgeted capital expenditures for the further development of our property base are $80.0 million during 2004, an increase from the $40.3 million spent on capitalized development during 2003. During the first nine months of 2004, we spent $52.8 million on development, which was a 102% increase from the $26.2 million spent on development during the first nine months of 2003. We also spent $445.3 million on acquisitions, funded primarily by borrowings under our credit facility, all in the third quarter of 2004. Although we have no specific budget for property acquisitions, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect to fund the remainder of our 2004 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $80.0 million, we could finance the additional capital expenditures with cash on hand, operating cash flow, borrowings under Whiting Oil and Gas Corporation s credit agreement, issuances of additional equity or development with industry partners. Our level of capital expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors.

Credit Facility. On September 23, 2004, Whiting Oil and Gas Corporation entered into an amended and restated $750.0 million credit agreement with a syndicate of banks. The new credit agreement increases our borrowing base to $480.0 million from $195.0 million under the prior credit agreement. The borrowing base under the credit agreement is determined in the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders and is subject to regular redetermination on May 1 and November 1 of each year as well as special redeterminations described in the credit agreement. On September 23, 2004, Whiting Oil and Gas Corporation borrowed $400.0 million under the credit agreement in order to (i) refinance the entire outstanding balance under the prior credit agreement and (ii) fund its $345.0 million acquisition of oil and natural gas producing properties in the Permian Basin. On September 30, 2004, we borrowed an additional $35.0 million to fund an additional acquisition.

The credit agreement provides for interest only payments until September 23, 2008, when the entire amount borrowed is due. In addition, the credit agreement provides that Whiting Oil and Gas Corporation will make principal payments under the credit agreement by May 1, 2005 to reduce the principal balance to $385.0 million. Whiting Oil and Gas Corporation may, throughout the four year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect from time to time. Interest accrues, at our option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. We have consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.250% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense.

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The credit agreement contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders and requires us to maintain a debt to EBITDAX (as defined in the credit agreement) ratio of less than 3.5 to 1 and a working capital ratio of greater than 1 to 1. The credit agreement also requires us to hedge at least 60%, but not more than 75%, of our total forecasted PDP production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps, with a minimum floor price of $35 per barrel of oil or $4.50 per MMbtu. After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDP production. In addition, while the credit agreement allows our subsidiaries to make payments to us so that we may pay interest on our senior subordinated notes, it does not allow our subsidiaries to make payments to us to pay principal on the senior subordinated notes. We were in compliance with our covenants under the credit agreement as of September 30, 2004. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation s assets. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee and Equity Oil Company has mortgaged substantially all of its assets as security for its guarantee.

7 1/4% Senior Subordinated Notes due 2012. On May 11, 2004, we issued, in a private placement, $150.0 million aggregate principal amount of our 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to retire all of our debt outstanding under Whiting Oil and Gas Corporation s credit agreement. The notes were issued at 99.26% of par and the associated discount is being amortized to interest expense over the term of the notes. On July 12, 2004, we completed an exchange offer in which we issued $150.0 million aggregate principal amount of new 7 1/4% senior subordinated notes due 2012 registered under the Securities Act of 1933 in exchange for the old notes. The notes are unsecured obligations of ours and are subordinated to all of our senior debt. The indenture governing the notes contains restrictive covenants that may limit our and our subsidiaries ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of us and our restricted subsidiaries taken as a whole and enter into hedging contracts. These covenants may limit the discretion of our management in operating our business. We were in compliance with these covenants as of September 30, 2004. Three of our subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company, have fully, unconditionally, jointly and severally guaranteed our obligations under the notes.

Alliant Energy Promissory Note. In conjunction with our initial public offering in November 2003, we issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005.

Tax Separation and Indemnification Agreement with Alliant Energy. In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with Alliant Energy. Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax basis of the assets of Whiting Oil and Gas Corporation and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. We have adjusted deferred taxes on our balance sheet to reflect the new tax basis of our assets. This additional basis is expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay to Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing our actual taxes to the taxes that would have been owed by us had the increase in basis not occurred. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years. The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders equity.

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Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of September 30, 2004 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include asset retirement obligations or production participation plan liabilities since we cannot determine with accuracy the timing of future payments. This table also does not include interest expense since we cannot determine with accuracy the timing of future loan advances and repayments and the future interest rate to be charged under floating rate instruments. During August 2004, we entered into an interest rate swap on $75.0 million of our $150.0 million fixed rate 7 1/4% senior subordinated notes due 2012. The amount of interest we expect to pay relating to the $75.0 million of our senior subordinated notes remaining under the 7 1/4% fixed rate is $1.4 million during the last three months of 2004, then $5.4 million annually through the term of the notes.

		Payments due by period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 588.8	$ 50.0	$ 3.1	$ 385.0	$ 150.7
Operating Lease	5.7	0.9	1.8	1.8	1.2
Tax Separation and Indemnification Agreement with Alliant Energy(1)	30.6		4.2	3.1	23.3
Total	$ 625.1	$ 50.9	$ 9.1	$ 389.9	$ 175.2

(1) Amounts shown are estimates based on estimated future income tax benefits from the increase in tax basis described under Tax Separation and Indemnification Agreement with Alliant Energy above.

Off-Balance Sheet Arrangements. As part of a 2002 purchase transaction, we agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2004 increased to 50% of the actual price received in excess of $19.77 per barrel. As of September 30, 2004, approximately 45,800 net barrels of crude oil per month (10% of October 2004 estimated net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. As of September 30, 2004, we have paid $6.1 million under this agreement and we have accrued an additional $427,000 as currently payable.

New Accounting Policies

In June 2001, the Financial Accounting Standards Board, or the FASB, issued SFAS No. 141, Business Combinations, which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, Goodwill and Other Intangible Assets, which discontinues the practice of amortizing goodwill and indefinite-lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. In March 2004, the Emerging Issues Task Force, or the EITF, reached a consensus that mineral rights, as defined in EITF Issue No. 04-02, Whether Mineral Rights Are Tangible Or Intangible Assets, are tangible assets and that they should be removed as examples of intangible assets in SFAS Nos. 141 and 142. The FASB has recently ratified this consensus and directed the FASB staff to amend SFAS Nos. 141 and 142 through the issuance of FASB Staff Position, or FSP, FAS Nos. 141-1 and 142-1. In addition, proposed FSP 142-b confirms that SFAS No. 142 does not change the balance sheet classification or disclosures of mineral rights of oil and gas producing enterprises. Historically, we have included the costs of such mineral rights as tangible assets, which is consistent with the EITF s consensus. As such, EITF 04-02 and the related FSPs have not affected our consolidated financial statements.

Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived

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assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to us, this statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million). We have an additional $4.3 million asset retirement obligations relating to our retained obligation with respect to the Point Arguello facility located offshore from California.

FASB Interpretation No. 45, or FIN 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others was issued in November 2002 by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligation it assumes under certain guarantees. Additionally, FIN 45 requires a guarantor to disclose certain aspects of each guarantee, or each group of similar guarantees, including the nature of the guarantee, the maximum exposure under the guarantee, the current carrying amount of any liability for the guarantee, and any recourse provisions allowing the guarantor to recover from third parties any amounts paid under the guarantee. The disclosure provisions of FIN 45 are effective for financial statements for both interim and annual periods ending after December 15, 2002. The fair value measurement provisions of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The adoption of this statement did not have a material impact on our financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. Our significant accounting policies are detailed in Note 1 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Revenue Recognition. We predominantly derive our revenue from the sale of produced crude oil and natural gas. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received; however, differences have been insignificant.

Hedging. Our crude oil and natural gas hedges are designed to be treated as cash flow hedges under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activity. This policy is significant since it impacts the timing of revenue recognition. Under this pronouncement, the majority of our hedging gains or losses are recorded in the month the contracts settle. We reflect this as an adjustment to revenue through the Gain (loss) on oil and gas hedging activities line item in our consolidated income statements. If our hedges did not qualify for cash flow hedge treatment, then our consolidated income statements could include large non-cash fluctuations in this line item, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

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Successful Efforts Accounting. We account for our oil and natural gas operations using the successful efforts method of accounting. Under this method, all costs associated with property acquisition, successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and natural gas production costs. All of our properties are located within the continental United States and the Gulf of Mexico.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this prospectus are prepared in accordance with guidelines established by the SEC and FASB. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Our proved reserve information included in this prospectus is based on estimates prepared by Ryder Scott Company, Cawley, Gillespie & Associates, Inc. and R.A. Lenser & Associates, Inc., each independent petroleum engineers, and Whiting Oil and Gas Corporation s engineering staff. The independent petroleum engineers evaluated approximately 83% of the pre-tax PV10% value of our proved reserves as of December 31, 2003 and Whiting Oil and Gas Corporation s engineering staff evaluated the remainder. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made.

Impairment of Oil and Natural Gas Properties. We review the value of our oil and natural gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. We provide for impairments on undeveloped property when we determine that the property will not be developed or a permanent impairment in value has occurred. Impairments of proved producing properties are calculated by comparing future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost at the end of each period. If the net capitalized cost exceeds net future cash flows, the cost of the property is written down to fair value, which is determined using net discounted future cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment.

Income Taxes. We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. Deferred income taxes are provided for the difference between the tax basis of assets and liabilities and the carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is settled. Since our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to actual in the period we file our tax returns.

Effects of Inflation and Pricing

We experienced increased costs during 2001, 2002 and 2003 due to increased demand for oil field products and services. The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Material changes in prices impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, continued high prices for oil and natural gas could result in increases in the cost of material, services and personnel.

Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on December 2003 production, our income before income taxes moves approximately $2.1 million for every $0.10 change in natural gas prices and approximately $2.4 million for each $1.00 change in crude oil prices.

We periodically enter into derivative contracts to manage our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been with no-cost collars, although we evaluate other forms of derivative instruments as well. Our derivative contracts have historically qualified for cash flow hedge accounting under SFAS No. 133. This accounting treatment allows the aggregate change in fair market value to be recorded as other comprehensive income on the consolidated balance sheet. Recognition in the consolidated income statement occurs in the period of contract settlement. Our credit agreement requires us to hedge at least 60%, but not more than 75%, of our total forecasted PDP production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps with a minimum floor price of $35 per barrel of oil or $4.50 per MMbtu. After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDP production. We also seek to diversify our hedge position with various counterparties where we have clear indications of their current financial strength.

Our outstanding hedges as of October 28, 2004 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Natural Gas	10/2004 to 12/2004	400,000	4.50/9.40
Natural Gas	10/2004 to 12/2004	400,000	4.50/12.00
Natural Gas	10/2004 to 12/2004	650,000	4.50/8.75
Natural Gas	01/2005 to 03/2005	400,000	5.00/12.75
Natural Gas	01/2005 to 03/2005	500,000	5.00/11.00
Natural Gas	01/2005 to 03/2005	600,000	5.00/10.50
Natural Gas	04/2005 to 06/2005	1,500,000	4.50/8.25
Natural Gas	07/2005 to 09/2005	1,500,000	4.50/8.60
Natural Gas	10/2005 to 12/2005	1,500,000	4.50/10.00
Crude Oil	10/2004 to 12/2004	50,000	28.00/46.10
Crude Oil	10/2004 to 12/2004	50,000	30.00/48.50

Crude Oil	10/2004 to 12/2004	44,000	35.00/51.90
Crude Oil	10/2004 to 12/2004	120,000	37.00/49.10
Crude Oil	10/2004 to 12/2004	50,000	37.00/54.75
Crude Oil	01/2005 to 03/2005	50,000	35.00/50.75
Crude Oil	01/2005 to 03/2005	94,000	35.00/49.60
Crude Oil	01/2005 to 03/2005	120,000	37.00/46.90
Crude Oil	01/2005 to 03/2005	80,000	37.00/50.60
Crude Oil	04/2005 to 06/2005	250,000	37.00/46.65
Crude Oil	07/2005 to 09/2005	250,000	35.00/47.25
Crude Oil	10/2005 to 12/2005	125,000	35.00/60.55
Crude Oil	10/2005 to 12/2005	125,000	35.00/65.75

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The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the natural gas contracts listed above, a hypothetical $0.10 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the gain (loss) on hedging activities of $145,000 for the remainder of 2004. For the crude oil contracts listed above, a hypothetical $1.00 change in the NYMEX price would cause a change in the gain (loss) on hedging activities of $314,000 for the remainder of 2004.

We have also entered into fixed price marketing contracts directly with end users for a portion of the natural gas we produce in Michigan. All of those contracts have built-in pricing escalators of 4% per year. Our outstanding fixed price marketing contracts at October 28, 2004 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2004 Price Per MMBtu
Natural Gas	01/2002 to 12/2011	51,000	$ 4.22
Natural Gas	01/2002 to 12/2012	60,000	$ 3.74

The table below summarizes the hedges and fixed price marketing contracts described above:

Hedges and Contracts Summary	Hedged and Contracted (MMBtu)/(Bbl) per Month	As a Percentage of Estimated October 2004 Production (Gas/Oil)
October December 2004	1,561,000/314,000	60%/69%
January March 2005	1,611,000/344,000	62%/75%
April June 2005	1,611,000/250,000	62%/55%
July September 2005	1,611,000/250,000	62%/55%
October December 2005	1,611,000/250,000	62%/55%
Thereafter	111,000/-0-	4%/-0-

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit facility. The credit facility allows us to fix the interest rate for all or a portion of the principal balance for a period up to six months. To the extent the interest rate is fixed, interest rate changes affect the instrument s fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. At September 30, 2004, our outstanding principal balance under our credit facility was $435.0 million and the interest rate on the entire outstanding principal balance was fixed at 3.34% through October 28, 2005. At September 30, 2004, the carrying amount approximated fair market value. Assuming a constant debt level of $588.8 million, the cash flow impact for 2004 resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $907,000.

Interest Rate Swap

In August 2004, we entered into an interest rate swap contract to hedge the fair value of $75 million of our 7 1/4% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the short cut method of assessing effectiveness under the provisions of Statement of Financial Accounting Standards No. 133, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that we receive the fixed rate of 7.25% and pay the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus our margin of 2.345% is less than 7.25%, we receive a payment from the counterparty equal to the difference in rate times $75 million for the six month period. When LIBOR plus our margin of 2.345% is greater than 7.25%, we pay the counterparty an amount equal to the difference in rate times $75 million for the six month period. As of September 30, 2004, we have recorded a long term derivative asset of $1.7 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding debt increase.

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BUSINESS AND PROPERTIES

About Our Company

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California regions of the United States. Our focus is on pursuing growth projects that we believe will generate attractive rates of return and maintaining a balanced portfolio of lower risk, long-lived oil and natural gas properties that provide stable cash flows.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through both property acquisitions and exploitation activities. As of January 1, 2004, our estimated proved reserves totaled 438.8 Bcfe, of which 75% were classified as proved developed. These estimated reserves had a pre-tax PV10% value of approximately $784.6 million, of which approximately 85% came from properties located in three states: Texas, North Dakota and Michigan. During 2003, we spent approximately $52.0 million on capital projects, including $38.8 million for the drilling of 72 gross (24.8 net) wells (64 successful completions and eight uneconomic wells), representing an 89% success rate. We have budgeted approximately $80.0 million for capital expenditures in 2004. Through September 30, 2004, we have invested $52.8 million of our budgeted expenditures for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate.

As of January 1, 2004, we had a balanced portfolio of oil and natural gas reserves, with approximately 53% of our proved reserves consisting of natural gas and approximately 47% consisting of oil. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to trailing 12 month production ending December 31, 2003 of approximately 11.8 years.

During 2004, we completed five separate acquisitions of producing properties with a combined purchase price of $516.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe, representing an average cost of approximately $1.22 per Mcfe of estimated proved reserves. We will continue to seek property acquisition opportunities that complement our existing core properties. We believe that our exploitation and acquisition expertise and our drilling inventory, together with our operating experience and efficient cost structure, provide us with the potential to continue our growth.

As of October 1, 2004, which includes the impact of these five acquisitions, our estimated proved reserves totaled 867.3 Bcfe, representing a 98% increase in proved reserves since January 1, 2004. Natural gas made up 39.0% of total proved reserves and 72% were classified as proved developed. Of these reserves, 38.8% were located in the Rocky Mountain region, 31.6% in the Permian Basin, 13.4% in the Gulf Coast, 11.4% in Michigan, 3.2% in the Mid-Continent region and 1.6% in California. Our estimated October 2004 average daily production is 177.7 MMcfe, representing a 75% increase over December 2003 average daily production and implying an average reserve life of approximately 13.4 years.

The following table summarizes our estimated proved reserves and pre-tax PV10% value within our core areas as of October 1, 2004 and our estimated October 2004 average daily production, each of which includes the impact of these five acquisitions.

	Proved Reserves	October 2004

Core Area	Oil (MMbbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	Pre-Tax PV10% Value (In millions)	Average Daily Production (MMcfe)
Permian Basin	37.7	47.9	274.2	17.5%	$ 731.5	41.4
Rocky Mountains[1]	43.3	76.3	336.4	22.7%	$ 716.1	65.1
Gulf Coast	3.3	96.2	115.8	83.0%	$ 324.2	39.2
Michigan	1.9	87.8	99.1	88.6%	$ 219.1	21.0
Mid-Continent	2.0	15.7	27.9	56.4%	$ 61.8	6.2
California	0.0	14.0	14.0	100.0%	$ 35.2	4.9
Total	88.2	337.9	867.3	39.0%	$ 2,087.9	177.7

(1) Includes one field in Canada with total estimated proved reserves of 5.2 Bcfe and a pre-tax PV10% value of $14.0 million.

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Recent Acquisitions

The following table summarizes certain information about the purchase price, estimated proved reserves and pre-tax PV10% value as of October 1, 2004 and estimated October 2004 average daily production for the five recent acquisitions described below.

		Proved Reserves						October 2004
	Purchase Price (In millions)	Oil (MMbbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	% Developed	Pre-Tax PV 10% Value (In millions)[6]	Average Daily Production (MMcfe)
Permian Basin[1] Properties	$ 345.0	34.2	44.6	250.0	17.8%	59%	$ 673.6	36.4
Equity Oil Company[2]	$ 72.6	10.2	42.1	103.6	40.6%	69%	$ 217.6	16.1
Colorado/ Wyoming[3]	$ 44.2	3.4	19.4	40.1	48.4%	82%	$ 76.6	8.6
Wyoming/Utah[4]	$ 35.0	3.6	11.1	32.6	34.1%	92%	$ 64.5	6.1
Louisiana/Texas[5]	$ 19.3	0.5	10.7	13.9	76.9%	57%	$ 39.5	3.5
Subtotal Acquisitions	$ 516.1	52.0	127.9	440.1	29.1%	66%	$ 1,071.8	70.7
Whiting Historical		36.2	210.0	427.2	49.2%	78%	$ 1,016.1	107.0
Total		88.2	337.9	867.3	39.0%	72%	$ 2,087.9	177.7

(1) Proved reserves are based on the reserve report prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers, as of July 1, 2004. Revenues and volumes are included in our results beginning September 23, 2004.

(2) Proved reserves are based on the reserve report prepared by Ryder Scott Company, L.P., independent petroleum engineers, as of December 31, 2003. Equity s results of operations and volumes are included in our results beginning July 20, 2004.

(3) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning August 13, 2004.

(4) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning September 30, 2004.

(5) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning August 16, 2004.

(6) These amounts were calculated using a period end average realized oil price of $45.87 per barrel and a period end average realized natural gas price of $5.64 per Mcf.

Permian Basin Properties

On September 23, 2004, we acquired interests in seventeen fields in the Permian Basin of West Texas and Southeast New Mexico, including interests in key fields such as Parkway Field in Eddy County, New Mexico; Would Have and Signal Peak Fields in Howard County, Texas; Keystone Field in Winkler County, Texas; and the DEB Field in Gaines County, Texas. The purchase price was $345.0 million in cash and was funded through borrowings under our bank credit agreement.

For the year ended December 31, 2003, these properties reported revenues in excess of direct operating expenses of $72.1 million. As of October 1, 2004, these properties had 250.0 Bcfe of estimated proved reserves, of which 17.8% were natural gas and 59% were classified as proved developed, and had a pre-tax PV10 value of estimated proved reserves of $673.6 million. The estimated October 2004 average daily production for these properties is approximately 36.4 MMcfe, implying an average reserve life of 18.8 years. We operate approximately 72% of the average daily production from these properties.

Low Cost Acquisition in Core Operational Area. Based on the purchase price of $345.0 million and estimated proved reserves of 251.6 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.37 per Mcfe of estimated proved reserves. We added approximately 300 operated producing wells in our Permian Basin core area with this acquisition.

Attractive Operating Cost Profile. The acquired Permian Basin properties operating performance is characterized by low operating costs. This acquisition was also attractive because average lease operating expense for these properties over the past three years was $0.68 per Mcfe in contrast to our historical lease operating expense of $1.01 per Mcfe for the same period. Additionally, we expect the anticipated incremental general and administrative expense for these properties to be lower than that of our existing operations given its overlap with our current operations in the Permian Basin. Including the impact of this acquisition, our Permian Basin region is now nearly as large as our Rocky Mountains core area, representing 31.6% and 38.8% of our total proved reserves as of October 1, 2004, respectively.

Additional Development Opportunities. We expect to leverage our operational and technical expertise in this core area to fully exploit the potential these properties present. We plan to continue the development of the PUD and other non-producing reserves we have acquired through this acquisition, and believe that this development offers us the opportunity to increase the current rate of production.

The following is a summary description our interests and activities in the five key fields identified above. Except where indicated, production numbers are as of September 30, 2004.

Parkway (Delaware) Unit. We own a 62% non-operated working interest (52% net interest) in the Parkway (Delaware) Unit, which is concentrated on 921 gross acres in Eddy County, New Mexico. September 2004 production averaged 1,782 bopd and 1,233 Mcf/d of natural gas (926 bopd, 641 Mcf/d, net). The first two wells of an ongoing infill program added over 500 bopd of new production. Wells are being drilled to convert the five spot flood pattern to a nine spot pattern. We have identified 17 PUD locations in this unit.

Would Have Field. We own a 75% operated working interest in the Would Have Field in Howard County, Texas, with a net production of 693 bopd and 496 Mcf/d of natural gas from 49 wells. Discovered in 2001 and covering over 13,000 gross acres, this field produces from two sub-units of the Clearfork Formation, the Would Have and the Dillard Limestones. A waterflood was initiated in the western half of the field in May 2004 and efforts are underway to expand the flood to the eastern portion of the field. The Would Have property is covered by proprietary 3-D seismic data. We believe that utilization of this 3-D dataset has led to the efficient development and delineation of the Would Have field. The Would Have Field is only partially developed, with both infill and step-out locations remaining to be drilled.

Signal Peak Field. Our Signal Peak property currently adds 168 bopd and 3.5 MMcf/d of natural gas from our operated wells. We own an average working interest of 72% in the property, of which we operate approximately 75%. The primary producing horizon in the Signal Peak Field is the Wolfcamp reservoir, with behind pipe Clearfork potential identified in several wells.

Keystone Field. Our 100% working interest in the Keystone Field provides both substantial production (561 bopd and 2.0 Mcf/d of natural gas) and a large portfolio of additional exploration and development opportunities. The property covers a surface area of 7,261 acres in Winkler County, Texas. Most current production comes from the Clearfork, although additional producing zones include the Wichita-Albany, Wolfcamp, Devonian, Silurian, McKee and Ellenburger. As a result of its multi-zone nature, many wells in the property contain several intervals of pay resulting in numerous behind-pipe recompletion opportunities. Most of the Keystone Field is covered by 3-D seismic data that has been used to make several discoveries, and we believe that drilling potential remains throughout this property. We have identified 20 PUD locations throughout the property.

DEB Field. We own a 100% working interest in the DEB Field that covers 738 acres in Gaines County, Texas and produces 723 bopd and 75 Mcf/d of solution gas from nine wells. The Wolfcamp reservoir is subdivided into two productive intervals, the A and the B, that both produce and are commingled in several wells. Current injection into the Wolfcamp is approximately 15,000 barrels of water per day and oil production in this long-life property has remained relatively flat for many years. Modifications have recently been completed increasing the fluid handling capability of the facilities. This will allow submersible pumps with increased capacity to be installed.

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Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our common stock to Equity s shareholders and repaid all of Equity s outstanding debt of $29.0 million under its credit facility. Equity s operations are focused primarily in California, Colorado, North Dakota and Wyoming.

For the year ended December 31, 2003, Equity reported income from continuing operations of $2.4 million, net cash provided by operating activities of $11.5 million and production of 6.6 Bcfe (45% natural gas). As of October 1, 2004, Equity had 103.6 Bcfe of estimated proved reserves, of which 40.6% were natural gas and 69% were classified as proved developed, and had a pre-tax PV10% value of estimated proved reserves of approximately $217.6 million. The estimated October 2004 average daily production from these properties is approximately 16.1 MMcfe, implying an average reserve life of 17.6 years.

Based on the purchase price of $72.6 million and estimated proved reserves of 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Addition of Long-life, Stable Reserves. With a reserve life index of over 17 years, the long-life Equity reserves are predominately in mature and predictable fields.

Expansion of Exploration and Exploitation Opportunities. With over 75,000 net undeveloped acres and 375 square miles of 3-D seismic, the Equity properties have added to our inventory of exploration, development and exploitation opportunities. We expect our strong financial position to allow more rapid development of these opportunities than Equity s cash flow permitted.

Creates Synergies and Cost Savings. We anticipate that combining the complementary operations of the two companies will allow us to take advantage of synergies and to realize cost savings.

The following is a summary description our interests and activities in Equity s properties.

Big Horn Basin. The Big Horn Basin of northwestern Wyoming has been a focus area for Equity since 1997. Big Horn Basin properties are typically long-lived high water cut oil fields, which benefit from our expertise in lift optimization and polymer injection technology to reduce water production. We operate 114 wells in the basin, producing just under 800 Boe per day. Our working interests in these wells range from 30% to 100%. The most significant asset in the Big Horn Basin is the Torchlight Field where we own a 100% working interest. During 2003 Equity completed several successful water shut-off treatments utilizing a polymer treatment developed by Marthon Oil Company. Five additional water shut-off treatments were performed during 2004. As a result, average monthly production during 2004 has been 8,617 barrels per month, which is 6% higher than the 2003 rate of 8,144 barrels per month. We plan to continue to utilize the water shut-off technology to increase production.

Williston Basin. During July 2003, Equity completed the #23-3 BR as the discovery well in the Roosevelt Creek Prospect in Golden Valley County, North Dakota. The #23-3 flowed 142 barrels of oil per day from the Nisku Formation at approximately 10,754 to 10,758 feet. Equity completed a stepout horizontal confirmation well, #11-10 Schieffer, pumping 117 barrels of oil per day, in December 2003. We are a 25% working interest owner in both wells. We have acquired 63 square miles of proprietary 3-D seismic data in the Roosevelt Creek and adjacent Beaver Creek Prospect areas where these two wells were drilled, and have identified drilling opportunities targeting oil in the Bakken, Nisku and Red River Formations. The Roosevelt Creek Prospect that Equity had developed is directly adjacent to the Nisku A project Whiting was pursuing. Additional information on this project follows. Our year-end independent reserve evaluation from Ryder Scott Company, L.P. included sixteen proved undeveloped drilling locations in these Prospect areas.

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Green River Basin Siberia Ridge. Equity owned working interests ranging from 40% to 100% in 5,730 gross acres (3,177 net) in Sweetwater County, Wyoming. Most of this acreage was developed with four to five wells per section. Production is from the Almond Formation at a depth of approximately 10,000 feet. In 2004, the Wyoming Oil and Gas Conservation Commission amended the existing spacing rules to allow up to 8 wells per section. As a result of this spacing change, there are 42 additional legal locations on the Equity acreage. Permitting efforts on the first 15 wells has been initiated and drilling is forecast to begin mid-2005.

Sacramento Basin. Effective January 1, 2002, Equity purchased an operated working interest in 27 producing gas wells and associated leasehold primarily in the Todhunters Lake and Willow Slough Fields of Yolo County, California. The acquisition included proved developed producing reserves, proved developed behind pipe recompletion opportunities and several drilling opportunities. During July 2003, Equity completed three development wells in the Todhunters Lake Field, where we maintain a 100% working interest. An active recompletion program has been undertaken since assuming operation of these properties to maintain production. During September 2004 production from the operated wells averaged 3.6 million cubic feet per day.

Other Cash Acquisitions of Properties

Colorado and Wyoming Properties. On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming from an undisclosed seller. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. We operate two of the fields and have an 84% average working interest in those fields. As of October 1, 2004, these interests had 40.1 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 8.6 MMcfe, implying an average reserve life of 12.7 years. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

One of the acquired fields, Hiawatha West, located in Moffat County, Colorado contains additional drilling opportunities. Four permitted well locations exist in the field, and we are in the process of locating equipment and contracting rigs to allow the drilling of these wells. An additional four proved undeveloped locations exist in the field.

Wyoming and Utah Properties. On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah from an undisclosed seller. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. As of October 1, 2004, these interests had 32.6 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 6.1 MMcfe, implying an average reserve life of 14.7 years. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

Louisiana and South Texas Properties. On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas from Delta Petroleum Corporation. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. We operate two of the fields and have a 93% average working interest in those fields. As of October 1, 2004, these interests had 13.9 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 3.5 MMcfe, implying an average reserve life of 11.0 years. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe of estimated proved reserves.

Business Strategy

Our goal is to increase stockholder value by investing in oil and gas projects with attractive rates of return on capital employed. We plan to achieve this goal by exploiting and developing our existing oil and natural gas properties and pursuing acquisitions of additional properties. Specifically, we have focused, and plan to continue to focus, on the following:

Developing and Exploiting Existing Properties. We believe that there is significant value to be created by drilling the numerous identified undeveloped opportunities on our properties. As of January 1, 2004, we owned

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interests in a total of 517,000 gross (206,000 net) developed acres. In addition, as of December 31, 2003, we owned interests in approximately 386,000 gross (188,000 net) undeveloped acres that contain many exploitation opportunities. During the three years ended December 31, 2003, we invested $94 million to participate in the drilling of 169 gross (60.6 net) wells, the majority of which were developmental wells, and 85.2% were successful completions. As of January 1, 2004, we had identified a total of 171 proved undeveloped drilling locations on our properties. We drilled or participated in the drilling of 72 gross (24.8 net) wells during the year ended December 31, 2003 and have budgeted approximately $80.0 million for the further development of our properties in 2004. Through September 30, 2004, we have invested $52.8 million of our budgeted expenditures for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate.

Pursuing Profitable Acquisitions. We have pursued and intend to continue to pursue acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have developed and refined an acquisition program designed to increase reserves and complement our existing core properties. We have an experienced team of management, engineering and geoscience professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties. During the first nine months of 2004, we completed five separate acquisitions of producing properties with a combined purchase price of $516.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe, representing a cost of $1.22 per Mcfe of estimated proved reserves. To secure attractive realized commodity prices on a portion of our volumes, we periodically enter into derivative contracts, typically no-cost collars. Given our recent acquisitions discussed above, and as an additional step toward realizing our profit potential from these acquisitions, we have increased our volumes subject to these collars to cover approximately 56% to 58% (excluding fixed price marketing contracts) of our natural gas volumes as of October 1, 2004 through December 2005 and between 55% and 75% of our crude oil volumes as of October 1, 2004 through December 2005. The average floor and ceiling for these volumes are approximately $4.60 and $9.59 per Mcf of natural gas, respectively, and $35.45 and $50.98 per bbl of crude oil, respectively.

Focusing on High Return Operated and Non Operated Properties. We have historically acquired operated as well as non operated properties that meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non operated property interests at attractive rates of return that provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non operated interests to the extent they meet our return criteria and further our growth strategy.

Controlling Costs through Efficient Operation of Existing Properties. We operate approximately 60% of the pre-tax PV10% value of our total proved reserves and approximately 82% of the pre-tax PV10% value of our proved undeveloped reserves, which we believe enables us to better manage expenses, capital allocation and the decision making processes related to our exploitation and exploration activities. For the year ended December 31, 2003, our lease operating expense per Mcfe averaged $1.16 and general and administrative costs averaged $0.34 per Mcfe produced, net of reimbursements.

Competitive Strengths

We believe that our key competitive strengths lie in our diversified asset base, our experienced management and technical team and our commitment to efficient utilization of new technologies.

Diversified Asset Base. As of January 1, 2004, we had interests in 5,006 wells in 16 states across our four core geographical areas of the United States. This property base, as well as our continuing business strategy of acquiring and developing properties in our core operating areas, presents us with a large number of opportunities for successful development and exploitation and additional acquisitions.

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Experienced Management Team. Our management team averages 27 years of experience in the oil and natural gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 20 years of experience in the evaluation, acquisition and operational assimilation of oil and natural gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated detailed geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Our technical team has access to approximately 575 square miles of 3-D seismic data that we have assembled primarily over the past five years. A team with access to state of the art geophysical/geological computer applications and hardware analyzes this information. Computer applications, such as the WellView® software system, enable us to quickly generate reports and schematics on our wells. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. This technology and expertise has greatly aided our pursuit of attractive development projects.

Proved Reserves

Our proved reserves as of January 1, 2004 are summarized in the table below.

	Oil (MBbl)	Natural Gas (MMcf)	Total (Bcfe)	% of Total Proved	Pre-tax PV10% (In thousands)	Future Capital Expenditures (In thousands)
Gulf Coast/Permian Basin:						
PDP	4,300	52,322	78.1	17.8%	$ 172,347	$ 2,784
PDNP	287	6,232	8.0	1.8%	20,465	1,141
PUD	939	30,856	36.4	8.3%	73,933	25,794
Total Proved:	5,526	89,410	122.5	27.9%	$ 266,745	$ 29,719
Rocky Mountains:						
PDP	18,898	13,183	126.6	28.8%	$ 169,051	$ 743
PDNP	571	205	3.6	0.8%	4,340	393
PUD	7,008	4,257	46.3	10.6%	87,680	18,774
Total Proved:	26,477	17,645	176.5	40.2%	$ 261,071	$ 19,910
Michigan:						
PDP	469	76,263	79.1	18.0%	$ 133,618	$ 0
PDNP	140	6,914	7.8	1.8%	23,854	1,713
PUD	536	24,017	27.2	6.2%	56,935	14,755
Total Proved:	1,145	107,194	114.1	26.0%	$ 214,407	$ 16,468
Mid-Continent:						
PDP	1,438	15,900	24.5	5.6%	$ 41,271	$ 0
PDNP	53	863	1.2	0.3%	1,129	229

Total Proved:	1,491	16,763	25.7	5.9%	$ 42,400	$ 229
Total Corporate:						
PDP	25,105	157,668	308.3	70.2%	$ 516,287	$ 3,527
PDNP	1,051	14,214	20.6	4.7%	49,788	3,476
PUD	8,483	59,130	109.9	25.1%	218,548	59,323
Total Proved:	34,639	231,012	438.8	100%	$ 784,623	$ 66,326

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Summary of Oil and Natural Gas Properties and Projects

Gulf Coast/Permian Basin Region

Our Gulf Coast/Permian Basin operations include assets in Texas, Louisiana, Alabama and New Mexico. The Gulf Coast/Permian Basin region contributes 122.5 Bcfe (73% natural gas) of net proved reserves to our portfolio of operations, which represents 27.9% of our total net proved reserves. Approximately 90.9% of the proved reserves of our Gulf Coast/Permian Basin operations are related to properties in Texas.

Stuart City Reef Trend. We have leasehold interests in five fields located along a regional geologic structure known as the Stuart City Reef Trend in south - central Texas, where we are employing horizontal drilling technologies to develop gas reserves in the Edwards Limestone at 14,000 feet. We are also adding new oil and gas reserves from multiple zones within the Wilcox formation at approximately 10,000 feet. As of December 31, 2003, our Stuart City properties contained 35.5 Bcfe of net proved reserves primarily within the Word North field, the Yoakum field and the Kawitt field. Since June 30, 2004, we have completed two successful Edwards wells in our Stuart City Reef Trend properties, which are producing at a combined rate of 5.9 MMcf per day. We have also completed three new Wilcox wells, which are producing at a combined rate of 3.9 MMcf per day. Since June 30, 2004, production volumes in our Stuart City fields have increased by 62% to 14.6 MMcf per day.

Vicksburg Trend. We own interests in several fields within the Vicksburg Trend located in the vicinity of Nueces Bay in San Patricio and Nueces Counties, Texas. These fields include the Agua Dulce, Triple A, South Midway, and East White Point fields. Natural gas and oil production in this area is from multiple, low permeability sandstone reservoirs within the Vicksburg and Frio Formations at depths ranging between 4,000 and 15,000 feet.

In the Agua Dulce field, we have drilled one well during 2004, the Matthews #1, which proved up production in a new separate fault block. This well averaged 1.2 MMcf/d with 80 bopd (gross) for the last week of September 2004. We are currently drilling the second well in Agua Dulce. We have entered into a multi-well program in the South Midway field where Whiting holds a non-operated interest. During the third quarter of 2004, two wells have been drilled. Each of these wells has encountered multiple gas pay zones and are currently being completed.

Rocky Mountain Region

Our Rocky Mountain operations include assets in North Dakota, Montana, Colorado and Wyoming. As of January 1, 2004, our proved reserves in the Rocky Mountain region were 29.4 MMboe (90% oil), which accounted for 40.2% of our total proved reserves. The majority of our interests in the Rocky Mountain region are within North Dakota and Montana, where we have interests in 97 fields, 45 of which we operate. Approximately 87% of the proved reserves of our Rocky Mountain operations are related to assets in North Dakota.

Big Stick (Madison) Unit. The Big Stick field, which contains the Big Stick (Madison) Unit, is located in Billings County, North Dakota and produces from a series of stacked, oil saturated, porous dolomites within the Mission Canyon Formation at an average depth of 9,400 feet. We operate this unit and own a 62% working interest. Our net recoverable reserves at Big Stick at year end were 12.6 MMboe. Since acquiring this property, we have increased unit oil production by 38% through a combination of new drilling and enhancements to the artificial lift system. Current daily production net to our interest is 1,052 bopd. During the past year, we have been engaged in a detailed reservoir modeling study to determine the benefits and feasibility of implementing a waterflood within the unit. We are also developing our deeper, non-unitized interests at

Big Stick, and recently drilled a new well which identified gas pay in the Red River Formation at 12,700 feet and oil pay in the Duperow Formation at 11,000 feet.

Nisku A Drilling Program. We have a new exploration program and acreage position in western Billings County, North Dakota. The MOI Stillwater 21-23H discovery well was a previously existing wellbore that was

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deepened and drilled 1,848 feet horizontally within the Nisku Formation. The initial producing rate averaged 397 barrels of oil and 256 Mcf/d on a 25/64th-inch choke with 200 psi flowing tubing pressure. We drilled three subsequent wells during the third quarter of 2004. Two of these wells have produced results exceeding those of the Stillwater well. We are currently employing two drilling rigs and plan to drill five additional wells during the fourth quarter of 2004. We have an average 93.7% working interest and 92.8% net revenue interest in this program. In addition, we have operated and non-operated interests in four new Nisku wells in Golden Valley County, North Dakota and two locations which are planned for the fourth quarter of 2004. Production from the new wells in this area is comparable to that in our Billings County wells. Our average working interest in these wells is 47.6%, with a 39.1% net revenue interest.

Michigan Region

Our Michigan operations include assets in Michigan and Ohio. Virtually all of the proved reserves and pre-tax PV10% value associated with our Michigan operations are from properties located in the State of Michigan. The Michigan region contributes 114.1 Bcfe (94% natural gas) of net proved reserves to our portfolio of operations, which represents 26% of our total net proved reserves.

The majority of our Michigan production is from a non-conventional natural gas reservoir in the northern Michigan basin known as the Antrim Shale. The remainder of our production is from a variety of conventional oil and natural gas reservoirs in the eastern and southern portions of the basin. We operate the majority of our non-Antrim production as well as the West Branch and Stoney Point natural gas plants, while the majority of our Antrim production is operated by local companies in close cooperation with our technical staff.

Antrim Production. Natural gas is produced from fractures within the Antrim Shale at depths from 1,200 to 2,200 feet. The productive fairway of the Antrim is widespread across northern Michigan, covering a 3,400 square mile region. We own interests in 57 multi-well Antrim Shale natural gas projects within this area. As of January 1, 2004, our net proved reserves from these projects were 79.6 Bcfe (100% natural gas).

Approximately 10 of our Antrim Shale projects have significant remaining development potential. These projects are concentrated in three areas. In Briley Township, we have proved undeveloped reserves of 5.9 Bcf. The Old Vandy Projects in Charlevoix and Otsego Counties have proved undeveloped reserves of 2.0 Bcf. An additional 4.9 Bcf of proved undeveloped reserves are present within eight additional townships which are less geographically concentrated. During 2003, we drilled 15 wells, and we expect to drill 20 wells during 2004.

Conventional (non-Antrim) Production. Our non-Antrim Shale production is from conventional reservoirs (primarily the Prairie du Chien, Trenton and Black River Formations) located in Central Michigan. Estimated net proved reserves from these properties total 34.5 Bcfe (80% natural gas). We have interests in 20 oil and natural gas fields in this region and operate 7 of them.

Our undeveloped potential resides in three fields, West Branch, Clayton and South Buckeye. All are structurally trapped hydrocarbon accumulations and to date recoveries range from 4% to 37% of the in place hydrocarbons. Our undeveloped proved reserve potential in these three fields is estimated at 14.4 Bcfe versus 60 Bcfe produced to date. We are planning on drilling two wells in Clayton Field and one Well in South Buckeye Field during the fourth quarter 2004 and first quarter of 2005.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. The Mid-Continent region contributes 25.7 Bcfe (65% natural gas) of net proved reserves to our portfolio of operations, which represents 5.9% of total net proved reserves. The majority of the proved value within our Mid-Continent operations is related to properties in Oklahoma. The Oklahoma production is scattered throughout the state, with the single largest concentration being in the company-operated Putnam Oswego Unit, located in Dewey and Custer Counties in West-Central Oklahoma.

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Our proved properties located in Arkansas are operated, and are primarily in two fields, the Magnolia Smackover Pool Unit and the Wesson Hogg Sand Unit. Both of these fields are mature pressure maintenance units.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2003 by region (net acreage is our percentage ownership of gross acreage). Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast/Permian Basin	159,603	58,813	8,514	7,518	168,117	66,331
Rocky Mountains	137,038	66,507	286,000	90,400	423,038	156,907
Michigan	179,141	59,000			179,141	59,000
Mid-Continent	40,740	21,438	91,284	90,395	132,024	111,833
Total	516,522	205,758	385,798	188,313	902,320	394,071

Production History

The following table presents the historical information about our produced natural gas and oil volumes.

	Year Ended December 31,		
	2003	2002	2001
Oil production (MMbbls)	2.6	2.3	2.1
Natural gas production (Bcf)	21.6	21.4	19.8
Total production (Bcfe)	37.2	35.2	32.4
Daily production (MMcfe/d)	101.8	96.4	88.8
Average sales prices:			
Natural gas (per Mcf)(1)	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)(1)	$ 27.50	$ 23.35	$ 23.85
Total (per Mcfe)(1)	$ 4.73	$ 3.48	$ 3.88
Costs and expenses (per Mcfe):			
Lease operating expenses	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expense	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.34	$ 0.34	$ 0.34

(1) Before consideration of hedging transactions.

Productive Wells

The following table presents our ownership at December 31, 2003 in productive oil and natural gas wells by region (a net well is our percentage ownership of a gross well).

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast/Permian Basin	1,571	139.7	852	282.0	2,423	421.7
Rocky Mountains	863	254.7	115	17.9	978	272.6
Michigan	78	57.0	968	368.3	1,046	425.3
Mid-Continent	372	151.2	187	78.8	559	230.0
Total	2,884	602.6	2,122	747.0	5,006	1,349.6

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Drilling Activity

We are engaged in numerous drilling activities on properties presently owned and intend to drill or develop other properties acquired in the future. The following table sets forth the results of our drilling activity for the last three years. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Gulf Coast/ Permian Basin			Mid-Continent			Rocky Mountains			Michigan		Total		
	2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2003	2002	2001
Gross:														
Productive	22	10	22	2	3	3	25	7	31	15	4	64	24	56
Dry	3	6	6				5	3	2			8	9	8
Total	25	16	28	2	3	3	30	10	33	15	4	72	33	64
Net:														
Productive	10.6	4.2	10.5	0.1	0.2	1.0	7.4	2.7	8.1	2.8	1.0	20.9	8.1	19.6
Dry	.9	2.2	1.9				3.0	2.1	1.9			3.9	4.3	3.8
Total	11.5	6.4	12.4	0.1	0.2	1.0	10.4	4.8	10.0	2.8	1.0	24.8	12.4	23.4

Our drilling activity from exploratory wells, which are included in the above table, include one productive gross well (0.2 net) in 2001 in the Gulf Coast/Permian Basin region, one dry gross well (0.15 net) in 2002 in the Gulf Coast/ Permian Basin region, three dry gross wells (1.55 net) in 2003, two of which were located in the Rocky Mountain region and one in the Gulf Coast/Permian Basin region.

Marketing and Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For fiscal year 2003, no single customer was responsible for generating 10% or more of our total oil and natural gas sales.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Whiting Oil and Gas Corporation s credit agreement is also secured by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interferes with the use of our properties in the operation of our business.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Regulation

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in inter state commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the Federal Energy Regulatory Commission, or the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act. The Decontrol Act removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC s pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect. While most major aspects of Order No. 637 have been upheld on judicial review, certain issues such as capacity segmentation and right of first refusal are pending further consideration by the FERC. We cannot predict what action FERC will take on these matters in the future, or whether the FERC s actions will survive further judicial review.

The Outer Continental Shelf Lands Act, which the FERC implements as to transportation and pipeline issues, requires that all pipelines operating on or across the outer continental shelf provide open access, non-discriminatory transportation service. One of the FERC s principal goals in carrying out this Act s mandate is to increase transparency in the market to provide producers and shippers on the outer continental shelf with greater assurance of open access services on pipelines located on the outer continental shelf and non-discriminatory rates and conditions of service on such pipelines.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

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Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Some of our offshore operations are conducted on federal leases that are administered by Minerals Management Service, or MMS, and are required to comply with the regulations and orders issued by MMS under the Outer Continental Shelf Lands Act. Among other things, we are required to obtain prior MMS approval for any exploration plans we pursue and our development and production plans for these leases. MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under limited circumstances, MMS could require us to suspend or terminate our operations on a federal lease.

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MMS also establishes the basis for royalty payments due under federal oil and natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and natural gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Regulations

General. Our oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, also referred to as the EPA, issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities, limit or prohibit project siting, construction, or drilling activities on certain lands laying within wilderness, wetlands, ecologically sensitive and other protected areas, require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for pollution resulting from our operations. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations. The regulatory burden on the oil and natural gas industry increases the cost of doing business and consequently affects its profitability.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and have not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this trend will continue in the future.

The environmental laws and regulations which have the most significant impact on the oil and natural gas exploration and production industry are as follows:

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as CERCLA or Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary operations, we may generate material that may fall within CERCLA s definition of a hazardous substance. Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these materials have been disposed or released.

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We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and natural gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other materials may have been disposed or released on, under, or from the properties owned or leased by us or on, under, or from other locations where these hydrocarbons and materials have been taken for disposal. In addition, many of these owned and leased properties have been operated by third parties whose management and disposal of hydrocarbons and materials were not under our control. Similarly, the disposal facilities where discarded materials are sent are also often operated by third parties whose waste treatment and disposal practices may not be adequate. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the disposal occurred before we acquired the property. Our properties, adjacent affected properties, the disposal sites, and the material itself may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed materials, including materials disposed or released by prior owners or operators or other third parties;

- to clean up contaminated property, including contaminated groundwater; or

- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators.

At this time, we do not believe that we are a potentially responsible party with respect to any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act. The Oil Pollution Act of 1990, also known as OPA, and regulations issued under OPA impose strict, joint and several liability on responsible parties for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A responsible party includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA establishes a liability limit for onshore facilities of $350 million while the liability limit for offshore facilities is the payment of all removal costs plus up to $75 million in other damages but these limits may not apply if a spill is caused by a party s gross negligence or willful misconduct, the spill resulted from violation of a federal safety, construction or operating regulation, or if a party fails to report a spill or to cooperate fully in a cleanup. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million ($10 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of financial responsibility required under OPA may be increased up to $150 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA s requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative, civil or criminal enforcement actions. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA s financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, also known as RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a generator or transporter of hazardous waste or an owner or operator of a hazardous waste treatment, storage or disposal facility. RCRA and many state counterparts specifically exclude from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy and thus we are not required to comply with a substantial portion of RCRA s requirements because our operations generate minimal quantities of hazardous wastes. However, these wastes may be regulated by EPA or state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes as they are presently classified to be significant, any repeal or modification of the oil and natural gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Clean Water Act. The Federal Water Pollution Control Act of 1972, or the Clean Water Act, imposes restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. In furtherance of the Clean Water Act, the EPA promulgated the Spill Prevention, Control, and Countermeasure, or SPCC, regulations, which require certain oil containing facilities to prepare plans and meet construction and operating standards. The SPCC regulations were revised in 2002 and will require the amendment of SPCC plans, if necessary to ensure compliance, in February 2006 with the implementation of such amended plans in August 2006. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution and that any amendment and subsequent implementation of our SPCC plans will be performed in a timely manner and not have a significant impact on our operations.

Clean Air Act. The Clean Air restricts the emission of air pollutants from many sources, including oil and natural gas operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants are being developed by the EPA, and may increase the costs of compliance for some facilities. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold or have applied for all permits necessary to our operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act, the National Environmental Policy Act, and the Coastal Zone Management Act require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. The Outer Continental Shelf Lands Act, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, the National Environmental Policy Act requires the Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement. The Coastal Zone Management Act, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the Department of Interior, we must certify that we will conduct our activities in a manner consistent with these regulations.

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Employees

As of September 30, 2004, we had 135 full-time employees, including five senior level geoscientists and fourteen petroleum engineers. Our employees are not represented by any labor union. We consider our relations with our employees to be satisfactory, and have never experienced a work stoppage or strike.

Legal Proceedings

In the ordinary course of business, we are a claimant or a defendant in various legal proceedings. In the opinion of our management, we do not have any litigation pending or threatened that is material.

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MANAGEMENT

Executive Officers and Directors

The following table sets forth information regarding our executive officers and directors as of September 30, 2004:

Name	Age	Position
James J. Volker	57	Chairman, President and Chief Executive Officer and Director
D. Sherwin Artus	66	Senior Vice President
James R. Casperson	57	Chief Financial Officer
James T. Brown	52	Vice President, Operations
John R. Hazlett	64	Vice President, Acquisitions and Land
J. Douglas Lang	54	Vice President Reservoir Engineering/Acquisitions
Patricia J. Miller	66	Vice President of Human Resources and Corporate Secretary
Mark R. Williams	48	Vice President, Exploration and Development
Michael J. Stevens	39	Controller and Treasurer
Thomas L. Aller	55	Director
Graydon D. Hubbard	70	Director
J. B. Ladd	80	Director
Palmer L. Moe	60	Director
Kenneth R. Whiting	76	Director

Our executive officers are elected by, and serve at the discretion of, our board of directors. The following biographies describe the business experience of our executive officers and directors:

James J. Volker joined us in August 1983 as Vice President of Corporate Development and served in that position through April 1993. In March 1993, he became a contract consultant to us and served in that capacity until August 2000, at which time he became Executive Vice President and Chief Operating Officer. Mr. Volker was appointed President and Chief Executive Officer and a director in January 2002 and Chairman of the Board in January 2004. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has over thirty years of experience in the oil and natural gas industry. Mr. Volker has a degree in finance from the University of Denver, a MBA from the University of Colorado and has completed H. K. VanPoolen and Associates course of study in reservoir engineering.

D. Sherwin Artus joined us in January 1989 as Vice President of Operations and became Executive Vice President and Chief Operating Officer in July 1999. In January 2000, he was appointed President and Chief Executive Officer and a director. In January 2002, he became Senior Vice President. He has been in the oil and natural gas business for over forty years. Mr. Artus holds a Bachelor s Degree in geologic engineering and a Master s Degree in mining engineering from the South Dakota School of Mines and Technology.

James R. Casperson joined us in February 2000 as Vice President of Finance and Chief Financial Officer. From June 1985 to February 2000, he was founder and president of Casperson, Inc., a private consulting firm. Mr. Casperson has twenty-six years of financial and operational experience in the oil and natural gas industry. Mr. Casperson holds a Bachelor s Degree from Texas Tech University.

James T. Brown joined us in May 1993 as a consulting engineer. In March 1999, he became Operations Manager and, in January 2000, he became Vice President of Operations. Mr. Brown has thirty years of oil and natural gas experience in the Rocky Mountains, Gulf Coast, California and Alaska. Mr. Brown is a graduate of the University of Wyoming, with a Bachelor s Degree in civil engineering and a MBA from the University of Denver.

John R. Hazlett joined us in January 1994 as Vice President of Land and Acquisitions. He has forty-one years of experience in the oil and natural gas industry as a land man and acquisitions team leader. Mr. Hazlett is a graduate of Ft. Hays State College in Hays, Kansas. Mr. Hazlett is a Certified Professional Landman.

J. Douglas Lang joined us in December 1999 as Senior Acquisition Engineer and became Manager of Acquisitions and Reservoir Engineering in January 2004 and Vice President Reservoir Engineering/Acquisitions in October 2004. His thirty years of acquisition and reservoir engineering experience has included staff and managerial positions with Amoco, Petro-Lewis, General Atlantic Resources, UMC Petroleum and Ocean Energy. Mr. Lang holds a Bachelor s Degree in Petroleum Engineering from the University of Wyoming and an MBA from the University of Denver. He is a registered Professional Engineer and has served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

Patricia J. Miller joined us in April 1980 as Corporate Secretary and as Secretary to our President, becoming Director of Human Resources in May 1994. In November 2001, she was appointed Vice President of Human Resources. Mrs. Miller attended business school at Otero Junior College in LaJunta, Colorado and at Texas A & I in Kingsville, Texas.

Mark R. Williams joined us in December 1983 as Exploration Geologist, becoming Vice President of Exploration and Development in December 1999. He has twenty-three years of experience in the oil and natural gas industry and his areas of primary technical expertise are in sequence stratigraphy, seismic interpretation and petroleum economics. Mr. Williams is a graduate of the Colorado School of Mines with a Master s Degree in geology and holds a Bachelor s Degree in geology from the University of Utah.

Michael J. Stevens joined us in May 2001 as Controller, and became Treasurer in January 2002. From 1993 until May 2001, he served as Chief Financial Officer, Controller, Secretary and Treasurer at Inland Resources Inc., a company engaged in oil and natural gas exploration and development. He spent seven years in public accounting with Coopers & Lybrand in Minneapolis, Minnesota. He is a graduate of Mankato State University of Minnesota and is a certified public accountant.

Thomas L. Aller has been a director of Whiting Petroleum Corporation since 2003 and has served as a director of Whiting Oil and Gas Corporation since 1997. Mr. Aller has served as Senior Vice President Energy Delivery of Alliant Energy Corporation and President of Interstate Power and Light Company since January 2004. Prior to that, he served as President of Alliant Energy Investments, Inc. since April 1998 and interim Executive Vice President Energy Delivery of Alliant Energy Corporation since September 2003. From 1993 to 1998, he served as Vice President of IES Investments. He received his Bachelor s Degree in political science from Creighton University and his Master s Degree in municipal administration from the University of Iowa.

Graydon D. Hubbard has served as a director of Whiting Petroleum Corporation since September 2003. He is a retired certified public accountant and was a partner of Arthur Andersen LLP in its Denver office for more than five years prior to his retirement in November 1989. Since 1991, he has served as a director of Allied Motion Technologies Inc., a company engaged in the business of designing, manufacturing and selling motion control products. Mr. Hubbard is also an author. He received his Bachelor s Degree in accounting from the University of Colorado.

J.B. Ladd has been a director of Whiting Petroleum Corporation since 2003 and has served as a director of Whiting Oil and Gas Corporation since its inception in 1980. He is an independent oil and natural gas operator with offices in Los Angeles, California and Denver, Colorado. He has over 50 years of experience in the oil and natural gas industry working for Texaco and Consolidated Oil and Gas, Inc. and as an independent oil and natural gas operator. He founded Ladd Petroleum Corporation in 1968, which was merged into Utah International in 1973 and later merged into General Electric Company in 1976. Mr. Ladd received a degree in petroleum engineering from the University of Kansas.

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Palmer L. Moe has served as a director of Whiting Petroleum Corporation since October 2004. He is Managing Director of Kronkosky Charitable Foundation in San Antonio, Texas, a position he has held since 1997. Mr. Moe is a certified public accountant and was a partner of Arthur Anderson & Co. in its San Antonio, Houston and Denver offices from 1965 to 1983. From 1983 until 1992, he served as President and Chief Operating Officer and a director of Valero Energy Corporation. He received his Bachelor s Degree in accounting from the University of Denver and completed the Senior Executive Development Course at the Alfred P. Sloan School of Management at the Massachusetts Institute of Technology.

Kenneth R. Whiting has been a director of Whiting Petroleum Corporation since 2003 and has served as a director of Whiting Oil and Gas Corporation since its inception in 1980. He was President and Chief Executive Officer of Whiting Oil and Gas Corporation from its inception until 1993, when he was appointed Vice President of International Business for IES Diversified. From 1978 to late 1979 he served as President of Webb Resources, Inc. He has many years of experience in the oil and natural gas industry, including his position as Executive Vice President of Ladd Petroleum Corporation. He was a partner and associate with Holme Roberts & Owen, Attorneys at Law. Mr. Whiting received his Bachelor s Degree in business from the University of Colorado and his J.D. from the University of Denver.

Board of Directors

Our certificate of incorporation and by-laws divide our board of directors into three classes. The directors serve staggered terms of three years, with the members of one class being elected in any year, as follows: (i) Palmer L. Moe and Kenneth R. Whiting have been designated as Class II Directors and will serve until the 2005 annual meeting of stockholders, (ii) Graydon D. Hubbard and James J. Volker have been designated as Class III Directors and will serve until the 2006 annual meeting of stockholders, and (iii) J.B. Ladd and Thomas L. Aller have been designated as Class I Directors and will serve until the 2007 annual meeting of stockholders, and in each case until their respective successors are duly elected and qualified.

Board Committees

Our board of directors has standing Audit, Compensation and Nominating and Governance Committees. Our board of directors has adopted a formal written charter for each of these committees.

The Audit Committee s primary duties and responsibilities are to assist our board of directors in monitoring the integrity of our financial statements, the independent auditor s qualifications and independence, the performance of our internal audit function and independent auditors and our compliance with legal and regulatory requirements. The Audit Committee is directly responsible for the appointment, retention, compensation, evaluation and termination of our independent auditors and has the sole authority to approve all audit and permitted non-audit engagement fees and terms. The Audit Committee is presently comprised of Messrs. Hubbard (Chairperson), Ladd and Moe, each of whom is an independent director under New York Stock Exchange listing standards applicable to directors generally and each of whom is an independent director under New York Stock Exchange listing standards and Securities and Exchange Commission rules applicable to Audit Committee members. Our board of directors has determined that Mr. Hubbard qualifies as an audit committee financial expert, as defined by Securities and Exchange Commission rules.

The Compensation Committee discharges the responsibilities of our board of directors with respect to our compensation programs and compensation of our executives and directors. The Compensation Committee has overall responsibility for approving and evaluating the compensation of executive officers (including the chief executive officer) and directors and our executive officer and director compensation plans, policies and programs. The Compensation Committee is presently comprised of Messrs. Hubbard (Chairperson), Ladd and Whiting, each of whom is an independent director under New York Stock Exchange listing standards.

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The principal functions of the Nominating and Governance Committee are to identify individuals qualified to become directors and recommend to our board of directors nominees for all directorships, identify directors qualified to serve on board committees and recommend to t our board of directors members for each committee, develop and recommend to our board of directors a set of corporation governance guidelines and otherwise take a leadership role in shaping our corporate governance. The Nominating and Governance Committee is presently comprised of Messrs. Hubbard, Moe and Whiting (Chairperson), each of whom is an independent director under New York Stock Exchange listing standards.

Director Compensation

Directors who are our employees receive no compensation for service as members of either the board of directors or board committees. Directors who are not our employees are paid an annual retainer of $20,000, an annual grant of $30,000 in restricted stock vesting ratably over a three year period and a fee of $1,500 for each board of directors meeting attended. Members of the Audit Committee receive an additional cash annual retainer of $2,500 ($12,000 for the chairman) and a fee of $1,500 for each Audit Committee meeting attended. Members of other board committees receive an additional cash annual retainer of $1,000 ($5,000 for the chairman) and a fee of $1,000 for each such committee meeting attended. In addition, Mr. Whiting receives payments under our Production Participation Plan with respect to his vested plan interests relating to his employment with us from 1982 to 1993. Mr. Whiting was paid $26,679 under the Production Participation Plan for 2003. Mr. Aller has received no compensation for his service on our board of directors to date because he is an employee of Alliant Energy Corporation, our former parent company.

Executive Officer Compensation

The following table sets forth certain information concerning the compensation earned each of the last two fiscal years by our Chief Executive Officer and each of four other most highly compensated executive officers whose total cash compensation exceeded $100,000 in the fiscal year ended December 31, 2003. The persons named in the table are sometimes referred to in this prospectus as the named executive officers.

Summary Compensation Table

		Annual Compensation		
Name and Principal Position	**Year**	**Salary($)**	**Bonus($)**[(1)]	**All Other Compensation($)**[(2)]
James J. Volker				
	2003	168,713	262,792	659,044
President and Chief Executive Officer	2002	165,000	205,041	
D. Sherwin Artus				
	2003	102,250	183,211	680,044
Senior Vice President	2002	173,309	156,641	11,000
John R. Hazlett				
	2003	115,952	139,133	653,042
Vice President, Acquisitions and Land	2002	112,050	114,941	11,000
Mark R. Williams	2003	95,406	150,672	626,041
	2002	91,510	124,819	11,000

Vice President, Exploration and Development

Patricia J. Miller				
	2003	99,579	138,930	427,988
Vice President, Human Resources and Corporate Secretary	2002	96,228	114,630	11,000

(1) Except for incentive bonuses to Mr. Volker of $54,788 for 2002 and $76,000 for 2003, all amounts presented under the Bonus column were paid under our Production Participation Plan, which is allocated a specific percentage of net income with respect to certain oil and natural gas wells.

(2) These amounts for 2003 consist of (i) matching contributions of $12,000 by us under our 401(k) Employee Savings Plan to each of the named executive officers other than Mr. Volker, who received no matching contribution, and Ms. Miller, who received a matching contribution of $11,960 and (ii) payments valued at

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$659,044 to Mr. Volker, $668,044 to Mr. Artus, $641,042 to Mr. Hazlett, $614,041 to Mr. Williams and $416,028 to Ms. Miller pursuant to our Phantom Equity Plan in connection with our initial public offering in November 2003. After withholding for taxes, these payments were made in the form of shares of our common stock resulting in the issuance of 25,052 shares to Mr. Volker, 25,394 shares to Mr. Artus, 24,368 shares to Mr. Hazlett, 23,341 shares to Mr. Williams and 15,814 shares to Ms. Miller. The Phantom Equity Plan terminated after the issuance of such shares.

Compensation Committee Interlocks and Insider Participation

During 2003, Graydon D. Hubbard, J.B. Ladd and Kenneth R. Whiting served on the Compensation Committee of our board of directors. Mr. Whiting was President and Chief Executive Officer of Whiting Oil and Gas Corporation from its inception in 1980 until 1993. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of directors or compensation committee.

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PRINCIPAL HOLDERS OF COMMON STOCK

Set forth below is information regarding the beneficial ownership of Whiting Petroleum Corporation common stock by Resources, each of our directors and executive officers, all directors and executive officers as a group and each other person known to us to beneficially own at least 5% of our outstanding common stock. Unless otherwise indicated, the address for each of the persons below is in care of our principal executive offices.

Beneficial ownership is determined under the rules of the Securities and Exchange Commission. In general, these rules attribute beneficial ownership of securities to persons who possess sole or shared voting power and/or investment power with respect to those securities and includes, among other things, securities that an individual has the right to acquire within 60 days. Unless otherwise indicated, the persons identified in the following tables have sole voting and investment power with respect to all shares shown as beneficially owned by them.

Alliant Energy Resources, Inc.

The following table sets forth certain information regarding the beneficial ownership by Resources and Alliant Energy of our common stock as of September 30, 2004 and as adjusted to give effect to the concurrent sale of 1,080,000 shares offered by Resources. This offering and the concurrent offering of 1,080,000 shares of our common stock by Resources are not contingent on one another. We will not receive any proceeds from the successful completion of the offering of our shares by Resources.

	Shares of Common Stock Beneficially Owned Prior to Concurrent Offering		Number of Shares	Shares of Common Stock Beneficially Owned After Concurrent Offering	
Name	Number	Percent	Being Offered	Number	Percent
Alliant Energy Corporation[(1)] 4902 North Biltmore Lane Madison, WI 53718	1,080,000	5.1%	1,080,000		

(1) Alliant Energy is the beneficial owner of the shares of common stock owned by its wholly-owned subsidiary, Resources.

Management and Directors

The following table sets forth certain information regarding the beneficial ownership of our common stock as of October 26, 2004 by: (i) each of our directors; (ii) each of the executive officers named in the Summary Compensation Table set forth under Management Executive Compensation ; and (iii) all of our directors and executive officers (including the executive officers named in the Summary Compensation Table) as a group. Each of the holders listed below has sole voting and investment power over the shares beneficially owned.

Name of Beneficial Owner	Shares of Common Stock Beneficially Owned	Percent of Common Stock Beneficially Owned
James J. Volker	56,047	*
Thomas L. Aller	1,300	*
Graydon D. Hubbard	7,545	*
J. B. Ladd	61,545	*
Palmer L. Moe	1,000	*
Kenneth R. Whiting	1,545	*
D. Sherwin Artus	33,118	*
John R. Hazlett	32,092	*
Mark R. Williams	26,815	*
Patricia J. Miller	21,063	*
All directors and executive officers as a group (14 persons)	351,737	1.7%

* Denotes less than 1%.

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Other Beneficial Owners

The following table sets forth certain information regarding beneficial ownership by the only persons known to Whiting to own more than 5% of its outstanding common stock other than Alliant Energy and Resources. The beneficial ownership information set forth below is as reported in filings made by the beneficial owners with the Securities and Exchange Commission.

	Amount and Nature of Beneficial Ownership					
	Voting Power		Investment Power			Percent
Name and Address of Beneficial Owner	Sole	Shared	Sole	Shared	Aggregate	of Class
Wellington Management Company, LLP 75 State Street Boston, MA 02109		1,479,850		1,760,230	1,760,230	9.4%
T. Rowe Price Associates, Inc. [(1)] 100 E. Pratt Street Baltimore, MD 21202	184,400		979,800		979,800	5.2%
Third Avenue Management LLC 622 Third Avenue, 32nd Floor New York, NY 10017	949,950		949,950		949,950	5.0%

(1) These securities are owned by various individual and institutional investors for which T. Rowe Price Associates, Inc. serves as investment adviser with power to direct investments and/or sole power to vote the securities. For purposes of the reporting requirements of the Securities Exchange Act of 1934, T. Rowe Price Associates, Inc. is deemed to be the beneficial owner of such securities; however, T. Rowe Price Associates, Inc. has expressly disclaimed beneficial ownership of such securities.

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RELATIONSHIP WITH ALLIANT ENERGY CORPORATION

Prior to our initial public offering in November 2003, we were a wholly-owned subsidiary of Resources, which is a wholly-owned subsidiary of Alliant Energy. In connection with our initial public offering, we entered into a series of agreements with Alliant Energy, including a master separation agreement, a tax separation and indemnification agreement and a registration rights agreement. We have set forth below a summary description of the material terms of each of those agreements.

Master Separation Agreement

In connection with our initial public offering, Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Alliant Energy and Resources entered into a master separation agreement. The master separation agreement contains provisions governing certain aspects of the relationship between us and Alliant Energy following the completion of the initial public offering, as summarized below.

Pursuant to the master separation agreement, immediately prior to the completion of our initial public offering, Resources transferred all of the outstanding stock of Whiting Oil and Gas Corporation to Whiting Petroleum Corporation in exchange for 18,330,000 shares of common stock of Whiting Petroleum Corporation, which constituted all of its outstanding common stock at such time, and a promissory note in the aggregate principal amount of $3.0 million. The promissory note bears interest at a fixed rate equal to 5.0% per year and the entire unpaid balance, together with interest, will be due and payable November 25, 2005.

The master separation agreement provides that we were responsible for withholding from payments to participants under our phantom equity plan all amounts required by law. Alliant Energy made a capital contribution to Whiting Oil and Gas Corporation equal to the aggregate amount of the tax withholding payments paid to the Internal Revenue Service or other appropriate governmental agency pursuant to the tax separation and indemnification agreement.

Alliant Energy agreed to indemnify us for any liabilities related to our initial public offering the substance of which is based solely on the information provided by Alliant Energy about Alliant Energy contained in certain sections of the prospectus relating to our initial public offering and for any liability resulting from the breach of any representation or covenant by Alliant Energy set forth in the master separation agreement, the registration rights agreement or the tax separation and indemnification agreement. We agreed to indemnify Alliant Energy for any other liabilities related to the registration statement relating to our initial public offering, and for all past, present and future liabilities associated with our business and operations (other than certain liabilities specified in the master separation agreement) and for any liability resulting from the breach of any representation or covenant by us set forth in the master separation agreement, the registration rights agreement or the tax separation and indemnification agreement.

Tax Separation and Indemnification Agreement

Prior to our initial public offering, Whiting Oil and Gas Corporation and its subsidiaries were members of the Alliant Energy consolidated tax group and were included in the consolidated federal income tax return filed by Alliant Energy, as well as various consolidated or combined state, local and foreign tax returns filed by Alliant Energy. As a result of the share exchange and the completion of our initial public offering, Whiting Oil and Gas Corporation and its subsidiaries ceased to be members of the Alliant Energy consolidated tax group and became members of our consolidated tax group and are included in the consolidated federal and certain other consolidated or combined state, local and foreign income tax returns filed by us.

In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with Alliant Energy. Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax basis of the assets of Whiting Oil and Gas Corporation and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. We have adjusted deferred taxes on our balance sheet to reflect the new tax basis of our assets. This additional basis is expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay to Alliant Energy 90% of the future tax benefits we realize annually as a result of this step-up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing our actual taxes to the taxes that would have been owed by us had the increase in basis not occurred. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years. The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders equity.

Registration Rights Agreement

In connection with our initial public offering, Whiting Petroleum Corporation, Alliant Energy and Resources entered into a registration rights agreement. The registration rights agreement provides that, at any time until November 25, 2006, Alliant Energy has the right to demand three registrations of its shares of our common stock. We have agreed to use our best efforts to file a registration statement with the SEC within 45 days of receipt of a request to do so and to use our best efforts to cause such registrations statement to become effective as soon as possible. If our board of directors determines in good faith that a registration statement would cause us to disclose material nonpublic information that would be materially detrimental to us or that would materially interfere with any material financing, acquisition, corporate reorganization or merger or other transaction involving us, then we may postpone filing a registration statement for up to 45 days once in a twelve month period. The registration rights agreement also provides that, until November 25, 2006, Alliant Energy will have the right to participate in any registration of shares of common stock by us, subject to customary limitations. All expenses payable in connection with such registrations will be paid by us, except that Alliant Energy will pay all underwriting discounts and commissions applicable to the sale of its shares of our common stock and the fees and expenses of its separate advisors and legal counsel.

The registration statement of which this prospectus is a part is intended to satisfy our obligations under the registration rights agreement. If Alliant Energy and Resources sell all of the 1,080,000 shares of our common stock registered for sale by them pursuant to such registration statement, then they will no longer own any shares of our common stock.

Other Relationships and Transactions

In 1994, we acquired a 6% working interest in the Point Arguello complex, consisting of working interests in the Point Arguello Unit located in federal waters offshore Santa Barbara County, California. Our wholly-owned subsidiary, Whiting Programs, Inc., became a partner in certain partnerships which owned onshore facilities that served the offshore unit. Resources has guaranteed the obligations of Whiting Programs, Inc. under the partnership agreements governing those partnerships.

We had borrowed a total of $80.5 million from Alliant Energy under a note that bore interest at 6.9% during 2003. We incurred approximately $1.2 million in interest expense related to this note during the year ended December 31, 2003. On March 31, 2003, Alliant Energy converted the outstanding balance of this note into our equity.

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DESCRIPTION OF CAPITAL STOCK

The authorized capital stock of Whiting Petroleum Corporation consists of 75,000,000 shares of common stock, $0.001 par value per share and 5,000,000 shares of preferred stock, $0.001 par value per share.

The following summary of the capital stock and certificate of incorporation and by-laws of Whiting Petroleum Corporation does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our certificate of incorporation and by-laws.

Common Stock

There were 21,100,347 shares of our common stock outstanding as of September 30, 2004. Holders of our common stock are entitled to one vote for each share held on all matters submitted to a vote of stockholders and do not have cumulative voting rights. Accordingly, holders of a majority of the shares of our common stock entitled to vote in any election of directors may elect all of the directors standing for election. Holders of our common stock are entitled to receive proportionately any dividends if and when such dividends are declared by our board of directors, subject to any preferential dividend rights of outstanding preferred stock. Upon the liquidation, dissolution or winding up of our company, the holders of our common stock are entitled to receive ratably our net assets available after the payment of all debts and other liabilities and subject to the prior rights of any outstanding preferred stock. Holders of our common stock have no preemptive, subscription, redemption or conversion rights. The rights, preferences and privileges of holders of our common stock are subject to, and may be adversely affected by, the rights of the holders of shares of any series of preferred stock that we may designate and issue in the future.

Preferred Stock

Under the terms of our certificate of incorporation, our board of directors is authorized to designate and issue shares of preferred stock in one or more series without stockholder approval. Our board of directors has discretion to determine the rights, preferences, privileges and restrictions, including voting rights, dividend rights, conversion rights, redemption privileges and liquidation preferences, of each series of preferred stock. It is not possible to state the actual effect of the issuance of any shares of preferred stock upon the rights of holders of our common stock until the board of directors determines the specific rights of the holders of the preferred stock. However, these effects might include:

- restricting dividends on the common stock;
- diluting the voting power of the common stock;
- impairing the liquidation rights of the common stock; and
- delaying or preventing a change in control of our company.

We have no present plans to issue any shares of preferred stock.

Delaware Anti-Takeover Law and Charter and By-law Provisions

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, the statute prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination or the transaction by which the person became an interested stockholder is approved by the corporation s board of directors and/or stockholders in a prescribed manner or the person owns at least 85% of the corporation s outstanding voting stock after giving effect to the transaction in which the person became an interested stockholder. The term business combination includes mergers, asset sales and other transactions resulting in a financial benefit to the interested stockholder. Subject to certain exceptions, an interested stockholder is a person who, together with affiliates and associates, owns, or within three years did own, 15% or more of the corporation s voting stock. A Delaware corporation may opt out from the application of Section 203 through a provision in its certificate of incorporation or by-laws. We have not opted out from the application of Section 203.

Under our certificate of incorporation and by-laws, our board of directors is divided into three classes, with staggered terms of three years each. Each year the term of one class expires. Any vacancies on the board of directors may be filled only by a majority vote of the remaining directors. Our certificate of incorporation and by-laws also provide that any director may be removed from office, but only for cause and only by the affirmative vote of the holders of at least 70% of the voting power of our then outstanding capital stock entitled to vote generally in the election of directors.

Our certificate of incorporation prohibits stockholders from taking action by written consent without a meeting and provides that meetings of stockholders may be called only by our chairman of the board, our president or a majority of our board of directors. Our by-laws further provide that nominations for the election of directors and advance notice of other action to be taken at meetings of stockholders must be given in the manner provided in our by-laws, which contain detailed notice requirements relating to nominations and other action.

The foregoing provisions of our certificate of incorporation and by-laws and the provisions of Section 203 of the Delaware General Corporation Law could have the effect of delaying, deferring or preventing a change of control of our company.

Liability and Indemnification of Officers and Directors

Our certificate of incorporation provides that our directors will not be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (1) for any breach of a director s duty of loyalty to us or our stockholders, (2) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (3) under Section 174 of the Delaware General Corporation Law, or (4) for any transaction from which the director derives an improper personal benefit. Moreover, the provisions do not apply to claims against a director for violations of certain laws, including federal securities laws. If the Delaware General Corporation Law is amended to authorize the further elimination or limitation of directors liability, then the liability of our directors will automatically be limited to the fullest extent provided by law. Our certificate of incorporation and by-laws also contain provisions to indemnify our directors and officers to the fullest extent permitted by the Delaware General Corporation Law. In addition, we may enter into indemnification agreements with our directors and officers. These provisions and agreements may have the practical effect in certain cases of eliminating the ability of stockholders to collect monetary damages from our directors and officers. We believe that these contractual agreements and the provisions in our certificate of incorporation and by-laws are necessary to attract and retain qualified persons as directors and officers.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, Inc.

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UNDERWRITING

We intend to offer the shares through the underwriters. Merrill Lynch, Pierce, Fenner & Smith Incorporated is acting as the representative of the underwriters named below. Subject to the terms and conditions described in a purchase agreement among us and the underwriters, we have agreed to sell to the underwriters, and the underwriters severally have agreed to purchase from us, the number of shares listed opposite their names below.

Underwriter	Number of Shares
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
A.G. Edwards & Sons, Inc.	
Banc of America Securities LLC	
J. P. Morgan Securities Inc.	
Raymond James & Associates, Inc.	
Petrie Parkman & Co., Inc.	
KeyBanc Capital Markets, a Division of McDonald Investments Inc.	
Simmons & Company International	
Total	

The underwriters have agreed to purchase all of the shares sold under the purchase agreement if any of these shares are purchased. If an underwriter defaults, the purchase agreement provides that the purchase commitments of the nondefaulting underwriters may be increased or the purchase agreement may be terminated.

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make in respect of those liabilities. These obligations are in addition to the contractual obligations between Alliant Energy and us. See Relationship with Alliant Energy Corporation Registration Rights Agreement.

The underwriters are offering the shares, subject to prior sale, when, as and if issued to and accepted by them, subject to approval of legal matters by their counsel, including the validity of the shares, and other conditions contained in the purchase agreement, such as the receipt by the underwriters of officer s certificates and legal opinions. The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or part.

Commissions and Discounts

The representatives have advised us that the underwriters propose initially to offer the shares to the public at the public offering price on the cover page of this prospectus and to dealers at that price less a concession not in excess of $ per share. The underwriters may allow, and the dealers may reallow, a discount not in excess of $ per share to other dealers. After the public offering, the public offering price, concession and discount may be changed.

The following table shows the public offering price, underwriting discount and proceeds to us before expenses. The information assumes either no exercise or full exercise by the underwriters of the overallotment option.

	Per Share	**Without Option**	**With Option**
Public offering price	$	$	$
Underwriting discount	$	$	$
Proceeds, before expenses, to us	$	$	$

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The expenses of the offering and the concurrent offering by Resources, not including the underwriting discounts, are estimated at $575,000 and are payable by us, except that Merrill Lynch has agreed to reimburse us for certain printing costs and legal and accounting fees and expenses relating to the concurrent offering by Resources.

Overallotment Option

We have granted an option to the underwriters to purchase up to 1,125,000 additional shares at the public offering price less the underwriting discount. The underwriters may exercise this option for 30 days from the date of this prospectus solely to cover any overallotments. If the underwriters exercise this option, each will be obligated, subject to conditions contained in the purchase agreement, to purchase a number of additional shares proportionate to that underwriter s initial amount reflected in the above table.

No Sale of Similar Securities

We, Resources, our executive officers and our directors have agreed, with exceptions, not to sell or transfer any of our common stock for 90 days after the date of this prospectus without first obtaining the written consent of Merrill Lynch on behalf of the underwriters. Specifically, we and these other individuals have agreed not to directly or indirectly

- offer, pledge, sell or contract to sell any common stock,
- sell any option or contract to purchase any common stock,
- purchase any option or contract to sell any common stock,
- grant any option, right or warrant for the sale of any common stock,
- lend or otherwise dispose of or transfer any common stock, or
- enter into any swap or other agreement that transfers, in whole or in part, the economic consequence of ownership of any common stock whether any such swap or transaction is to be settled by delivery of shares or other securities, in cash or otherwise.

This lock-up provision applies to common stock and to securities convertible into or exchangeable or exercisable for or repayable with common stock. It also applies to common stock owned now or acquired later by the person executing the agreement or for which the person executing the agreement later acquires power of disposition.

New York Stock Exchange Listing

The shares are listed on the New York Stock Exchange under the symbol WLL.

Price Stabilization, Short Positions and Penalty Bids

Until the distribution of the shares is completed, SEC rules may limit underwriters and selling group members from bidding for and purchasing our common stock. However, the representative may engage in transactions that stabilize the price of the common stock, such as bids or purchases to peg, fix or maintain that price.

If the underwriters create a short position in the common stock in connection with the offering, i.e., if they sell more shares than are listed on the cover of this prospectus, the representative may reduce that short position by purchasing shares in the open market. The representative may also elect to reduce any short position by exercising all or part of the overallotment option described above. Purchases of our common stock to stabilize its price or to reduce a short position may cause the price of our common stock to be higher than it might be in the absence of such purchases.

Neither we nor any of the underwriters makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor any of the underwriters makes any representation that the representative will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Electronic Distribution

Merrill Lynch will be facilitating Internet distribution for this offering to certain of its Internet subscription customers. Merrill Lynch intends to allocate a limited number of shares for sale to its online brokerage customers. An electronic prospectus is available on the Internet Website maintained by Merrill Lynch. Other than the prospectus in electronic format, the information on the Merrill Lynch Website is not part of this prospectus.

Other Relationships

Some of the underwriters and their affiliates have engaged in, and may in the future engage in, investment banking and other commercial dealings in the ordinary course of business with us. In addition, affiliates of J. P. Morgan Securities Inc., Banc of America Securities LLC and KeyBanc Capital Markets, a Division of McDonald Investments Inc. are lenders under Whiting Oil and Gas Corporation s bank credit facility and each will receive its proportionate share of the net proceeds of the offering used to repay a portion of the outstanding balance under the credit facility. Because more than ten percent of the net proceeds may be paid to affiliates of members of the National Association of Securities Dealers, Inc. participating in the offering, the offering will be conducted in accordance with NASD Conduct Rule 2710(c)(8).

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LEGAL MATTERS

The validity of the shares of common stock to be sold in the offering will be passed upon for us by the law firm of Foley & Lardner LLP. Welborn Sullivan Meck & Tooley, P.C. will pass on certain legal matters relating to us and our subsidiaries for us in connection with this offering. Certain legal matters will be passed upon for the underwriters by the law firm of Vinson & Elkins L.L.P.

EXPERTS

The consolidated financial statements of Whiting Petroleum Corporation as of December 31, 2003 and 2002 and for each of the three years in the period ended December 31, 2003, included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein (which report expresses an unqualified opinion and includes an explanatory paragraph referring to a change in Whiting Petroleum Corporation s method of accounting for asset retirement obligations effective January 1, 2003) and have been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

The statements of revenues and direct operating expenses of the Permian Basin Acquisition Properties for the years ended December 31, 2003, 2002 and 2001, included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein and have been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

Certain information with respect to our oil and natural gas reserves derived from the reports of Cawley Gillespie & Associates, Inc., R.A. Lenser & Associates, Inc. and Ryder Scott Company, L.P., each independent petroleum engineering consultants, has been included in this prospectus on the authority of said firms as experts in petroleum engineering.

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WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. We have also filed with the SEC under the Securities Act a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other document are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained from the SEC at prescribed rates. Information on the public reference facilities may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed through the SEC s EDGAR System. The web site can be accessed at *http://www.sec.gov*.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of

Whiting Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and Subsidiaries (the Company) as of December 31, 2003 and 2002, and the related consolidated statements of income, stockholder s equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations to conform to Statement of Financial Accounting Standards No. 143.

/s/ DELOITTE & TOUCHE LLP

February 25, 2004

Denver, Colorado

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF DECEMBER 31, 2003 AND 2002

(In thousands, except per share data)

	2003	2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 53,585	$ 4,833
Accounts receivable trade	24,020	22,509
Income taxes and other receivables		8,162
Prepaid expenses and other	2,666	3,542
Total current assets	80,271	39,046
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	615,764	553,902
Unproved properties	1,637	1,593
Other property and equipment	2,684	3,454
Total property and equipment	620,085	558,949
Less accumulated depreciation, depletion and amortization	(192,794)	(154,352)
Property and equipment net	427,291	404,597
OTHER LONG-TERM ASSETS	9,988	4,825
DEFERRED INCOME TAX ASSET	18,735	
TOTAL	$ 536,285	$ 448,468

(Continued)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF DECEMBER 31, 2003 AND 2002

(In thousands, except per share data)

	2003	2002
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 15,918	$ 8,474
Oil and gas sales payable	2,406	903
Accrued employee benefits	5,275	4,259
Production taxes payable	2,574	2,137
Derivative liability	2,145	3,300
Income taxes and other liabilities	693	585
Total current liabilities	29,011	19,658
DEFERRED INCOME TAX LIABILITY		28,235
ABANDONMENT LIABILITY	23,021	4,232
PRODUCTION PARTICIPATION PLAN LIABILITY	7,868	8,053
TAX SHARING LIABILITY	28,790	
LONG-TERM DEBT	188,017	265,472
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS EQUITY:		
Common stock, $.001 par value; 18,750,000 authorized, issued and outstanding	19	19
Additional paid-in capital	170,367	53,219
Accumulated other comprehensive loss	(223)	(1,550)
Retained earnings	89,415	71,130
Total stockholders equity	259,578	122,818
TOTAL	$ 536,285	$ 448,468

See notes to consolidated financial statements.

(Concluded)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

	2003	2002	2001
REVENUES:			
Oil and gas sales	$ 175,731	$ 122,709	$ 125,286
Gain (loss) on oil and gas hedging activities	(8,680)	(3,184)	2,266
Gain on sale of oil and gas properties		978	11,698
Interest income and other	330	9	205
Total	167,381	120,512	139,455
COSTS AND EXPENSES:			
Lease operating	43,213	32,867	29,767
Production taxes	10,691	7,363	6,482
Depreciation, depletion and amortization	41,256	43,601	26,904
Exploration	3,186	1,811	793
General and administrative	12,805	11,980	10,939
Phantom equity plan	10,914		
Interest expense	9,177	10,938	10,233
Total costs and expenses	131,242	108,560	85,118
INCOME BEFORE INCOME TAXES	36,139	11,952	54,337
INCOME TAX EXPENSE (BENEFIT):			
Current	2,389	(6,408)	1,815
Deferred	11,560	10,631	11,279
Total income tax expense	13,949	4,223	13,094
INCOME FROM CONTINUING OPERATIONS	22,190	7,729	41,243
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3,905)		
NET INCOME	$ 18,285	$ 7,729	$ 41,243
Basic and diluted earnings per share from continuing operations	$ 1.18	$ 0.41	$ 2.20
Cumulative change in accounting principle	(0.20)		
BASIC AND DILUTED NET INCOME PER COMMON SHARE	$ 0.98	$ 0.41	$ 2.20
WEIGHTED AVERAGE SHARES OUTSTANDING	18,750	18,750	18,750

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity	Comprehensive Income
BALANCES January 1, 2001	18,750	$ 19	$ 47,856	$ 22,158	$ 15	$ 70,048	
Net income				41,243		41,243	41,243
Unrealized net gain on marketable equity securities for sale					88	88	88
Reclass to earnings					87	87	87
BALANCES December 31, 2001	18,750	19	47,856	63,401	190	111,466	41,418
Net income				7,729		7,729	7,729
Unrealized net gain on marketable equity securities for sale					240	240	240
Tax contribution from Alliant			5,363			5,363	
Change in derivative instrument fair value					(1,980)	(1,980)	(1,980)
BALANCES December 31, 2002	18,750	19	53,219	71,130	(1,550)	122,818	5,989
Net income				18,285		18,285	18,285
Unrealized net gain on marketable equity securities for sale					664	664	664
Change in derivative instrument fair value					663	663	663
Conversion of Alliant note payable to equity			80,931			80,931	
Issuance of note payable			(3,000)			(3,000)	
Phantom equity plan contribution			10,666			10,666	
Tax basis step-up			28,551			28,551	
BALANCES December 31, 2003	18,750	$ 19	$ 170,367	$ 89,415	$ (223)	$ 259,578	$ 19,612

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

(In thousands, except per share data)

	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 18,285	$ 7,729	$ 41,243
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of oil and gas properties		(978)	(11,700)
Depreciation, depletion and amortization	41,256	43,601	35,902
Deferred income taxes	11,560	10,631	11,288
Amortization of bank fees	1,091	71	
Accretion of tax sharing agreement	220		
Phantom equity plan	6,510		
Cumulative change in accounting principle	3,905		
Changes in assets and liabilities:			
Accounts receivable	(307)	(1,129)	2,165
Income taxes and other receivable	3,814	1,538	(5,670)
Other assets	295	(1,229)	315
Abandonment liability	(147)	(48)	(8,997)
Production participation plan	651	1,685	1,473
Current liabilities	9,229	710	(3,672)
Net cash provided by operating activities	96,362	62,581	62,347
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(47,555)	(165,443)	(99,621)
Acquisition of partnership interests, net of cash received	(4,453)		
Proceeds from sale of properties		1,534	19,570
Restricted cash		6,434	(6,434)
Net cash used in investing activities	(52,008)	(157,475)	(86,485)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Other advances (repayments) from Alliant, net	4,616	(83,119)	23,869
Proceeds from bank loan		185,000	
Debt issuance costs	(218)	(3,171)	
Net cash provided by financing activities	4,398	98,710	23,869
NET CHANGE IN CASH AND CASH EQUIVALENTS	48,752	3,816	(269)
CASH AND CASH EQUIVALENTS:			
Beginning of period	4,833	1,017	1,286
End of period	$ 53,585	$ 4,833	$ 1,017

SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes Alliant	$ (1,425)	$ (7,946)	$ 8,586
Cash paid for interest	$ 6,464	$ 10,866	$ 10,233
NONCASH FINANCING ACTIVITIES:			
Alliant debt converted to equity	80,931		

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations Whiting Petroleum Corporation (Whiting or the Company) is a Delaware corporation that prior to its initial public offering in November 2003 was a wholly owned indirect subsidiary of Alliant Energy Corporation (Alliant Energy or Alliant), a holding company whose primary businesses are utility companies. Just prior to the public offering of our common stock by Alliant Energy, the Company in effect split its common stock, issuing 18,330 shares for the 1 previously held by Alliant Energy. All periods presented have been adjusted to reflect the current capital structure. Alliant Energy historically provided the Company with cash management and other services. Whiting acquires, develops and explores for producing oil and gas properties primarily in the Gulf Coast/Permian Basin, Rocky Mountains, Michigan, and Mid-Continent regions of the United States.

Basis of Presentation of Consolidated Financial Statements The consolidated financial statements include the accounts of Whiting and its subsidiaries, all of which are wholly owned, together with its pro rata share of the assets, liabilities, revenue and expenses of limited partnerships in which Whiting is the sole general partner. All significant intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make significant estimates. These estimates are an integral part of the financial statements and actual results could differ from those estimates. Certain estimates associated with the carrying amount of oil and gas properties are particularly sensitive to changes in pricing, production rates and cost. A decline in the price of oil or gas or rate of production or increase in costs associated with the operations of oil and gas properties could adversely impact the economic value of the oil and gas properties.

Cash and Cash Equivalents Cash equivalents consist of money market accounts and investments which have an original maturity of three months or less.

Fair Value of Financial Instruments The Company s financial instruments, including cash and cash equivalents, restricted cash, accounts receivable and payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The related party debt and bank loan have a recorded value that approximates its fair value as both instruments have variable interest rates tied to current market rates. The Company s derivative instruments and investment in available for sale securities are marked-to-market with changes in value being recorded in accumulated other comprehensive income.

Concentration of Credit Risk Substantially all of the Company s receivables are within the oil and gas industry, primarily from the sale of oil and gas products and billings to working interest owners. Although diversified within many companies, collectibility is dependent upon the general economic conditions of the industry. Most of the receivables are not collateralized and to date, the Company has had minimal bad debts.

Further, our natural gas futures and swap contracts also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and historically the Company have not experienced material credit losses. The Company believes that our credit risk related to the natural gas futures and swap contracts is no greater than the risk associated with primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; but, as a result of Whiting s hedging activities the Company may be exposed to greater credit risk in the future. No single purchaser of oil and gas accounted for 10% or more of total sales for the years ended December 31, 2003, 2002 or 2001.

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At December 31, 2003 and 2002, the Company had recorded an allowance for doubtful accounts of $300 and $250 and, respectively.

Oil and Gas Producing Activities The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs are charged to expense. The costs of development wells are capitalized whether productive or nonproductive.

Interest cost is capitalized as a component of property cost for exploration and development projects that require a period of time to be reaided for their intended use. During 2003, 2002 and 2001, capitalized interest was insignificant.

Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment is recorded for unproved properties if the capitalized costs are not considered to be realizable. Depletion, depreciation and amortization (DD&A) of capitalized costs of proved oil and gas properties is provided on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and the Company s expected cost to abandon its well interests.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost at the end of each period. If the net capitalized cost exceeds net future cash flows, then the cost of the property is written down to fair value, which is determined using net discounted future cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. During 2003, 2002 and 2001, the Company did not record any impairment charges for proved properties.

Gains and losses are recognized on sales of entire interests in proved and unproved properties. Sales of partial interests are generally treated as recoveries of costs.

Other Property and Equipment Other property and equipment are stated at cost and depreciated using the straight-line method over a period of four years. Maintenance and repair costs which do not extend the useful lives of the property and equipment are charged to expense as incurred. When other property and equipment is sold or retired, the related costs and accumulated depreciation are removed from the accounts.

As of December 31, 2003 and 2002, the balance of other property and equipment was $2,684 and $3,454, respectively. Depreciation expense was approximately $836, $770, and $710 for the years ended December 31, 2003, 2002 and 2001, respectively.

Bank Fees Bank fees are being amortized to interest expense using the interest method over the life of the loan.

Reimbursed Overhead The Company provides various administrative services to its partnerships and owners of certain oil and gas properties for which the Company receives overhead reimbursements. Amounts earned are included as a reduction to general and administrative expense and totaled $5,631, $5,505 and $5,276, for the years ended December 31, 2003, 2002 and 2001, respectively.

Abandonment Liability Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations*. This Statement generally applies to legal obligations

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize the fair value of asset retirement obligations in the financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to the Company, this Statement applies directly to the plug and abandonment liabilities associated with the Company s net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to depreciation, depletion and amortization expense. If the obligation is settled for other than the carrying amount, then a gain or loss is recognized on settlement.

Revenue Recognition The Company uses the sales method to record oil revenues whereby revenue is recognized based on the amount of oil sold to purchasers. The Company uses the entitlements method to record natural gas revenues whereby revenue is recognized for the Company s share of natural gas produced, regardless of whether the Company has taken its share of the related revenue. In situations where gas imbalances occur, receivables are valued at current market value each reporting period, while liabilities are generally presented based on the price in effect when the imbalance occurred. As of December 31, 2003 and 2002, the Company was in an under produced imbalance position of approximately 206,000 Mcf and 411,000 Mcf.

Derivative Instruments Whiting is exposed to market risk in the pricing of its oil and gas production. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, transportation availability and price, and general economic conditions. Worldwide political developments have historically also had an impact on oil and gas prices. Periodically, Whiting utilizes oil and gas swaps and forward contracts to mitigate the impact of oil and gas price fluctuations related to its sales of oil and gas. During the years 2003, 2002 and 2001, Whiting entered into a number of oil and gas swaps and forward contracts.

At December 31, 2003, the Company had five commodity swaps or forward contracts outstanding with a fair market value unrealized loss of $2,145 of which $1,317 was recorded as a component of accumulated other comprehensive loss and $828 was recorded as an increase to the deferred tax asset.

At December 31, 2002, the Company had four commodity swaps or forward contracts outstanding with a fair market value unrealized loss of $3,300 of which $1,980 was recorded as a component of accumulated other comprehensive loss and $1,320 was recorded as a reduction to the deferred tax liability.

For the years ended December 31, 2003, 2002, and 2001, Whiting recognized a loss of approximately $8.7 million, a loss of approximately $3.2 million, and a gain of $2.3 million from the settlement of derivative instruments, respectively.

Marketable Securities Investments in marketable securities are classified as held-to-maturity, trading securities or available-for-sale. Trading and available-for-sale securities are recorded at estimated market value. Realized gains or losses for both classes of equity investments are determined on a specific identification basis and are included in income. Unrealized gains or losses of available-for-sale securities are excluded from earnings and reported in other comprehensive income.

As of December 31, 2003 and 2002, the Company had equity investments in publicly traded securities classified as available-for-sale (included in other long term-assets) with an original cost to the Company of $585 and a fair value of approximately $2,367 and $1,300, respectively. As of December 31, 2003, the Company recorded an unrealized holding gain of $1,782, correspondingly $1,094 was recorded as a component of accumulated other comprehensive income and $688 was recorded as a decrease to the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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(In thousands, except per share data)

deferred tax asset. As of December 31, 2002, the Company recorded an unrealized holding gain of $715 of which $430 was recorded as a component of accumulated other comprehensive income and $285 was recorded as a deferred tax liability.

Income Taxes Prior to the Company s initial public offering in November 2003, the Company was included in the consolidated federal income tax return of Alliant Energy but was treated as a separate entity for income tax purposes. The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company s assets and liabilities.

Earnings Per Share Basic net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding during each year. Diluted net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding and other dilutive securities. There were no potentially dilutive securities of the Company outstanding for any of the periods presented.

Industry Segment and Geographic Information The Company operates in one industry segment, which is the exploration, development and production of natural gas and crude oil, and all of the Company s operations are conducted in the United States. Consequently, the Company currently reports as a single industry segment.

New Accounting Pronouncements In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations* which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The Company did not change or reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 142. The Company believes the current accounting of such mineral rights as part of crude oil and natural gas properties is appropriate under the successful efforts method of accounting. However, there is an alternative view that reclassification of mineral rights to an intangible assets may be necessary. If a reclassification of contractual mineral rights acquired subsequent to July 1, 2001 from oil and gas properties to long term intangible assets is required, then the reclassified amount as of December 31, 2003 and 2002 would be approximately $160.1 million and $161.2 million, respectively. Management does not believe that the ultimate outcome of this issue will have a significant impact on the Company s cash flows, results of operations or financial condition.

In June 2002 the FASB issued SFAS No. 146, *Accounting for Costs Associates with Exit or Disposal Activities*. This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)*. The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of this Statement had no impact on the financial statements.

FASB Interpretation No. 45 (FIN 45), *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* was issued in November 2002, by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligation it assumes under certain guarantees. Additionally, FIN 45 requires a guarantor to disclose certain aspects of each guarantee, or each group of similar guarantees, including the nature of the guarantee, the maximum

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exposure under the guarantee, the current carrying amount of any liability for the guarantee, and any recourse provisions allowing the guarantor to recover from third parties any amounts paid under the guarantee. The disclosure provisions of FIN 45 are effective for financial statements for both interim and annual periods ending after December 15, 2002. The fair value measurement provisions of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The adoption of this Statement did not have a material impact on the financial statements. Under the disclosure provisions, the Company, as part of a 2002 purchase transaction, agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2004 increased to 50% of the actual price received in excess of $19.77 per barrel. Approximately 46,000 net barrels of crude oil per month are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. As of December 31, 2003, the Company has paid $3.1 million under this agreement and has accrued an additional $215 as currently payable.

In January 2003, the FASB issued FASB Interpretation No. 46 (as revised in December 2003), *Consolidation of Variable Interest Entities* (FIN 46). FIN 46 clarifies the application of Accounting Research Bulletin No. 51, *Consolidated Financial Statements* to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support from other parties. FIN 46 requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. All companies with interests in variable interest entities created after January 31, 2003, shall apply the provisions of FIN 46 to those entities immediately. The adoption of this Statement had no impact on the Company s financial statements.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* to amend and clarify financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. The changes in this statement require that contracts with comparable characteristics be accounted for similarly to achieve more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and will be applied prospectively. The adoption of this Statement had no impact on the financial statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* to classify certain financial instruments as liabilities in statements of financial position. The financial instruments are mandatorily redeemable shares, which the issuing company is obligated to buy back in exchange for cash or other assets, put options and forward purchase contracts, instruments that do or may require the issuer to buy back some of its shares in exchange for cash or other assets, and obligations that can be settled with shares, the monetary value of which is fixed, tied solely or predominantly to a variable such as a market index, or varies inversely with the value of the issuers shares. Most of the guidance in SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The adoption of this Statement had no impact on the financial statements.

2. ASSET RETIREMENT OBLIGATIONS

The Company s estimated liability for plugging and abandoning its oil and gas wells and certain obligations for previously owned onshore and offshore facilities in California is discounted using a credit-adjusted risk-free rate of approximately 7%. Upon adoption of SFAS No. 143, the Company recorded an increase to its

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discounted abandonment liability of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from the amount recorded upon adoption of SFAS No. 143 on January 1, 2003 (including its previously recognized liability in California) through December 31, 2003.

Beginning asset retirement obligation	$ 4,232
SFAS 143 adoption	16,458
Additional liability incurred	996
Accretion expense	1,482
Liabilities settled	(147)
Ending asset retirement obligation	$ 23,021

No revisions have been made to the timing or the amount of the original estimate of undiscounted cash flows during 2003.

3. INVESTMENT IN PARTNERSHIPS

The Company sponsors private oil and gas income and development limited partnerships. The partnership agreements generally provide for a capital contribution by the Company of 8% to 10% of total capital for a 13% to 17% interest in the net revenue of the partnerships. Additionally, Whiting is a general partner in various partnerships which own and operate transportation and gas processing facilities. As a general partner in these partnerships, Whiting may be liable to the extent any such partnerships incur liabilities in excess of the value of its assets.

In 2003, the Company purchased the limited partnership interests in three limited partnerships in which the Company was general partner for $4,453.

4. RELATED PARTY TRANSACTIONS

In conjunction with the Company s initial public offering in November 2003, the Company issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005 (see Note 5).

Alliant Energy had loaned the Company an aggregate $80.5 million as of December 31, 2002. The note bore interest at a floating rate which ranged from 6.9% to 4.4% during 2003 and 2002, respectively. On March 31, 2003, Alliant Energy converted its outstanding intercompany balance of $80,931 to equity of the Company. The Company incurred approximately $1.2 million, $10.5 million and $10.2 million, in interest expense related to this note during the years ended December 31, 2003, 2002 and 2001, respectively.

The Company holds a 6% working interest in four federal offshore platforms and related onshore plant and equipment in California. Alliant Energy has guaranteed the Company s obligation in the abandonment of these assets.

The Company provides general and administrative services to its partnerships for which the partnerships are billed monthly. Amounts so charged are based on flat rates provided for in each respective Partnership

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(In thousands, except per share data)

Agreement. The Company pays operating expenses for its partnerships for which it receives reimbursement. The Company may also advance funds to its partnerships for property development. The amounts due from/to affiliates represent the net amount of advances to partnerships for property development offset by proceeds on sales of property and cash receipts from the sale of oil and gas to be distributed to the partnerships.

5. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2003 and 2002:

	2003	2002
Bank borrowings	$ 185,000	$ 185,000
Alliant see Note 4	3,017	80,472

Credit Facility The Company has a $350.0 million credit agreement with a syndicate of banks. At December 31, 2003, the credit agreement provided a borrowing base of $210.0 million with an outstanding principal balance of $185.0 million. On February 17, 2004, the Company repaid $40.0 million of the outstanding principal balance from cash on hand in excess of projected drilling and production needs. The borrowing base under the credit agreement is based on the collateral value of the Company s proved reserves and is subject to redetermination on May 1 and November 1 of each year. If the borrowing base is determined to be lower than the outstanding principal balance then drawn, the Company must immediately pay the difference. The credit agreement provides for interest only payments until December 20, 2005, when the entire amount borrowed is due. Interest accrues, at the Company s option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0.25% to 1.0% depending on the ratio of the amounts borrowed to the borrowing base, or (2) at the LIBOR rate plus a margin where the margin varies from 1.5% to 2.25% depending on the ratio of the amounts borrowed to the borrowing base. At December 31, 2003, all amounts outstanding under the credit agreement bore interest at an annual rate of 3.21% through February 6, 2004.

On February 6, 2004, the Company fixed the rate on the outstanding principal balance at an annual rate of 3.2% through August 6, 2004. The credit agreement has covenants that restrict the payment of cash dividends, borrowings, sale of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders and requires the Company to maintain certain debt to EBITDAX (as defined in our credit agreement) ratios and a working capital ratio. The credit agreement also precludes the Company from providing any cash to Alliant Energy except for services rendered on an arm s-length basis or for income taxes. The Company was in compliance with the covenants under the credit agreement as of December 31, 2003. The credit agreement is secured by a first lien on substantially all of Whiting s assets.

6. EMPLOYEE BENEFIT PLANS

The Company has a Production Participation Plan for all employees. On an annual basis, management and the Board of Directors allocate interests in oil and gas properties acquired or developed during the year to the plan on a discretionary basis. Once allocated, the interests (not legally conveyed) are fixed and plan participants generally vest ratably over five years. Forfeitures are re-allocated among other Plan participants. Allocations prior to 1995 consisted of 2% 3% overriding royalty interests. Allocations since 1995 have been 2% 5% net revenue interests.

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Payments to participants of the plan are made annually in cash after year end and amounted to $4.4 million, $3.6 million and $4.1 million for 2003, 2002 and 2001, respectively. The Company has estimated the total discounted obligations, including the amounts above, at December 31, 2003 and 2002 as being $12.3 million and $11.7 million, respectively. Plan expense for 2003, 2002 and 2001 was approximately $4.3 million, $5.3 million and $5.6 million, respectively.

The Company s Board of Directors adopted the Whiting Petroleum Corporation 2003 Equity Incentive Plan on September 17, 2003. Two million shares of the Company s common stock have been reserved for issuance under this plan. No participating employee may be granted options for more than 300,000 shares of common stock, stock appreciation rights with respect to more than 300,000 shares of common stock or more than 150,000 shares of restricted stock during any calendar year. This plan prohibits the repricing of outstanding stock options without stockholder approval. As of December 31, 2003, no awards had been made under this plan.

The Company also had a phantom equity plan as an incentive to employees. The phantom equity plan award was calculated based on the growth of the Company s proved oil and gas reserves before income taxes from January 1, 2000 to a triggering event, less increases in debt for the same period (the Value Appreciation). The Value Appreciation was then multiplied by a sharing percentage of 5%. The completion of the initial public offering in November 2003 constituted a triggering event under the plan and, consequently, the Company s employees received a $10.9 million award in the form of approximately 420,000 shares of Whiting common stock after withholding of shares for payroll and income taxes. Alliant Energy was required to fund the majority of plan expense by contributing cash and stock to the Company in the combined amount of $10.7 million, which is reflected as an increase to additional paid-in capital. The phantom equity plan is now terminated.

The Company also has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. The Company s contributions for 2003, 2002 and 2001 were approximately $665, $529 and $287, respectively. Employer contributions vest ratably at 20% per year over a five year period.

7. COMMITMENTS AND CONTINGENCIES

The Company leases administrative office space under an operating lease arrangement through October 2005. Net rental expense for 2003, 2002, and 2001 amounted to approximately $1,046, $916 and $823, respectively. A summary of future minimum lease payments under this noncancellable-operating lease as of December 31, 2003 is as follows (in thousands):

Year Ending December 31	
2004	$ 1,084
2005	929

Total	$ 2,013

The Company had a $2.5 million unused line of credit with a bank. Interest on the line of credit was prime plus one percent. The line of credit was cancelled in February 2003.

The Company is subject to litigation claims and governmental and regulatory controls arising in the ordinary course of business. It is the opinion of the Company s management that all claims and litigation involving the Company are not likely to have a material adverse effect on its financial position or results of operations.

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Tax Separation and Indemnification Agreement with Alliant Energy In connection with Whiting s initial public offering in November 2003, the Company entered into a tax separation and indemnification agreement with Alliant Energy. Pursuant to this agreement, the Company and Alliant Energy made a tax election with the effect that the tax basis of the assets of Whiting and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to reflect the new tax basis of the Company s assets. This additional basis is expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by Whiting. Under this agreement, the Company has agreed to pay to Alliant Energy 90% of the future tax benefits the Company realizes annually as a result of this step-up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing the Company s actual taxes to the taxes that would have been owed by the Company had the increase in basis not occurred. In 2014, Whiting will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years. Future tax benefits in total will approximate $62 million. The Company has estimated total payments to Alliant will approximate $49 million given the discounting affect of the final payment in 2014. The Company has discounted all cash payments to Alliant at the date of the Tax Separation Agreement.

The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders equity. The Company will monitor the estimate of when payments will be made and adjust the accretion of this liability on a prospective basis. There is a provision in the Tax Separation Agreement that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in a corresponding adjustment of the Alliant liability. For purposes of this calculation, management has assumed that no such change will occur during the term of this agreement.

8. INCOME TAXES

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax bases of assets and liabilities and amounts reported in the Company s balance sheet. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liability determines the periodic provision for deferred taxes.

Prior to the Company s initial public offering, the Company was included in the consolidated federal income tax return of Alliant Energy and calculated its income tax expense on a separate return basis at Alliant Energy s effective tax rate less any research or Section 29 tax credits generated by the Company. Current tax due under this calculation was paid to Alliant Energy, and current refunds were received from Alliant Energy. All income taxes receivable or payable at December 31, 2003 were to/from Alliant Energy. Section 29 tax credits of $5,363 were generated in 2002 and are expected to be utilized by Alliant Energy in the future. However, on a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. Under the Company s tax separation and indemnification agreement with Alliant Energy, Whiting will be paid for the Section 29 credits when Alliant Energy receives the benefit for them. These credits were reported as a credit to additional paid-in capital in 2002.

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Income tax expense differed from amounts computed by applying the U.S. Federal income tax rate as follows (in thousands):

	2003	2002	2001
Expected statutory tax expense at 35%	$ 12,649	$ 4,183	$ 19,018
Research and Section 29 tax credits		(178)	(6,575)
Excess percentage depletion	(216)	(82)	(268)
State tax expense, net of federal benefit	1,516	300	918
	$ 13,949	$ 4,223	$ 13,093

Temporary differences between the financial statement carrying amounts and tax bases of assets and liabilities that give rise to the net deferred tax asset or (liability) result from the following components (in thousands):

	2003	2002
Oil and gas properties	$ (2,893)	$ (32,290)
Production participation plan	2,993	3,020
Available for sale securities	(127)	(285)
Derivative instruments	828	1,320
Tax sharing agreement	11,028	
Abandonment obligations	3,028	
Net operating loss carryforward	3,878	
	$ 18,735	$ (28,235)

The Company s net operating loss will expire in 2023.

9. OIL AND GAS ACTIVITIES

The Company s oil and gas activities are conducted entirely in the United States. Costs incurred in oil and gas producing activities are as follows (in thousands):

	2003	2002	2001
Unproved property acquisition	$ 242	$ 851	$ 105
Proved property acquisition	10,914	140,708	66,024
Development	40,336	23,136	32,073
Exploration	3,186	1,811	793
Subtotal	54,678	166,506	98,995
Asset retirement obligations	996		
Total	$ 55,674	$ 166,506	$ 98,995

During 2003, additions to oil and gas properties of approximately $996 were recorded for the estimated costs related to new wells drilled or acquired.

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Net capitalized costs related to the Company s oil and gas producing activities are summarized as follows (in thousands):

	2003	2002
Proven oil and gas properties	$ 615,764	$ 553,902
Unproven oil and gas properties	1,637	1,593
Accumulated depreciation, depletion and amortization	(191,488)	(152,595)
Oil and gas properties net	$ 425,913	$ 402,900

During 2003, the Company recorded an addition to oil and gas properties of approximately $10.1 million for the asset retirement costs related to the adoption of SFAS No. 143.

10. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The estimate of proved reserves and related valuations were based upon the reports of Ryder Scott Company L.P., and Cawley, Gillespie & Associates, Inc. and R. A. Lenser & Associates, Inc., each independent petroleum and geological engineers, and the Company s engineering staff, in accordance with the provisions of Statement of Financial Accounting Standards No. 69 (SFAS No. 69), *Disclosures about Oil and Gas Producing Activities*. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

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The Company s oil and gas reserves are attributable solely to properties within the United States. A summary of the Company s changes in quantities of proved oil and gas reserves for the years ended December 31, 2003, 2002 and 2001, are as follows:

	Oil (Mbbls)	Gas (Mmcf)
Balance January 1, 2001	19,121	157,521
Extensions and discoveries	1,086	9,320
Sales of minerals in place	(677)	(6,045)
Purchases of minerals in place	945	89,760
Production	(2,088)	(19,751)
Revisions to previous estimates	(3,582)	(3,284)
Balance December 31, 2001	14,805	227,521
Extensions and discoveries	473	2,346
Sales of minerals in place		(953)
Purchases of minerals in place	15,244	58,381
Production	(2,319)	(21,366)
Revisions to previous estimates	1,255	(29,941)
Balance December 31, 2002	29,458	235,988
Extensions and discoveries	2,327	17,097
Sales of minerals in place		
Purchases of minerals in place	822	3,996
Production	(2,594)	(21,596)
Revisions to previous estimates	4,627	(4,474)
Balance December 31, 2003	34,640	231,011
Proved developed reserves:		
December 31, 2001	11,046	136,817
December 31, 2002	23,784	167,618
December 31, 2003	26,157	171,881

As discussed in Note 6 Employee Benefit Plans, all of the Company s employees participate in the Company s production participation plan. The reserve disclosures above include oil and gas reserve volumes that have been allocated to the production participation plan. Once allocated to plan participants, the interests are fixed. Allocations prior to 1995 consisted of 2% 3% overriding royalty interest while allocations since 1995 have been 2% 5% of net income from the oil and gas production allocated to the plan.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with the provisions of SFAS No. 69. Future cash inflows were computed by applying prices at year end to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income

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tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of the Company s oil and gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves are as follows (in thousands):

	2003	2002	2001
Future cash flows	$ 2,297,935	$ 1,854,886	$ 880,890
Future production costs	(879,390)	(677,146)	(379,732)
Future development costs	(66,326)	(65,440)	(75,575)
Future income tax expense	(336,165)	(270,516)	(62,025)
Future net cash flows	1,016,054	841,784	363,558
10% annual discount for estimated timing of cash flows	(426,490)	(365,755)	(151,823)
Standardized measure of discounted future net cash flows	$ 589,564	$ 476,029	$ 211,735

Future cash flows as shown above were reported without consideration for the effects of hedging transactions outstanding at each period end. If the effects of hedging transactions were included in the computation, then future cash flows would have decreased by $145 in 2003 and $1,300 in 2002 and $0 in 2001, respectively.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and gas reserves are as follows (in thousands):

	2003	2002	2001
		(in thousands)	
Beginning of year:	$ 476,029	$ 211,735	$ 519,197
Sale of oil and gas produced, net of production costs	(121,827)	(80,337)	(87,273)
Sales of minerals in place		(739)	(11,200)
Net changes in prices and production costs	108,115	212,191	(528,096)

Extensions, discoveries and improved recoveries	47,183	6,587	17,511
Development costs-net	(886)	(11,328)	(3,322)
Purchases of mineral in place	16,745	241,798	84,613
Revisions of previous quantity estimates	43,679	(36,164)	(16,205)
Net change in income taxes	(42,082)	(116,854)	183,051
Accretion of discount	62,901	24,786	73,516
Changes in production rates and other	(293)	24,354	(20,057)
End of year	$ 589,564	$ 476,029	$ 211,735

Average wellhead prices in effect at December 31, 2003, 2002 and 2001 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows (in thousands):

	2003	2002	2001
Oil (per Bbl)	$ 29.43	$ 28.21	$ 17.30
Gas (per Mcf)	$ 5.52	$ 4.39	$ 2.72

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

11. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2003, 2002, and 2001 (in thousands except per share data) (in thousands):

	Three Months Ended			
	March 31, 2003	**June 30, 2003**	**September 30, 2003**	**December 31, 2003**
Year ended December 31, 2003:				
Oil and gas sales	$ 49,483	$ 41,883	$ 42,272	$ 42,093
Income (loss) before income tax and cumulative effect of change in accounting principle	11,935	11,481	12,885	(162)
Cumulative effect of change in accounting principle	(3,905)			
Net income (loss)	3,559	7,053	7,989	(316)
Basic net income (loss) per share	0.19	0.38	0.43	(0.02)

	Three Months Ended			
	March 31, 2002	**June 30, 2002**	**September 30, 2002**	**December 31, 2002**
Year ended December 31, 2002:				
Oil and gas sales	$ 20,190	$ 29,552	$ 34,657	$ 38,310
Income (loss) before income tax	(2,977)	3,277	6,191	5,461
Net income	(1,822)	2,050	3,877	3,624
Basic net income (loss) per share	(0.10)	0.11	0.21	0.19

12. SUBSEQUENT EVENT

On February 2, 2004, Whiting announced that the Company entered into a definitive merger agreement to acquire Equity Oil Company. The merger agreement provides for a stock-for-stock merger under which Equity shareholders will receive a fixed exchange ratio of 0.185 shares of Whiting common stock for each share of Equity common stock that they own. In addition, Whiting will assume approximately $29 million of Equity debt. The merger is subject to the approval of shareholders owning two-thirds of the outstanding Equity shares and other customary closing conditions. Equity intends to call a special meeting of its shareholders during the second quarter of 2004 to consider and vote on the merger. The Company expects to complete the merger as soon as practicable following approval by Equity s shareholders.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2004 (Unaudited) AND DECEMBER 31, 2003

(In thousands)

	September 30, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 17,361	$ 53,585
Accounts receivable trade, net	35,322	24,020
Prepaid expenses and other	6,488	2,666
Total current assets	59,171	80,271
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	1,193,090	615,764
Unproved properties	4,325	1,637
Other property and equipment	3,616	2,684
Total property and equipment	1,201,031	620,085
Less accumulated depreciation, depletion and amortization	(225,275)	(192,794)
Total property and equipment-net	975,756	427,291
OTHER LONG-TERM ASSETS	19,624	9,988
DEFERRED INCOME TAX ASSET		18,735
TOTAL	$ 1,054,551	$ 536,285

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2004 (Unaudited) AND DECEMBER 31, 2003

(In thousands)

	September 30, 2004	December 31, 2003
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 23,280	$ 15,918
Oil and gas sales payable	4,051	2,406
Accrued employee benefits	4,788	5,275
Production taxes payable	7,580	2,574
Derivative liability	9,850	2,145
Income taxes and other liabilities	200	693
Current portion of long-term debt	50,000	
Total current liabilities	99,749	29,011
ASSET RETIREMENT OBLIGATIONS	30,502	23,021
PRODUCTION PARTICIPATION PLAN LIABILITY	8,833	7,868
TAX SHARING LIABILITY	30,590	28,790
LONG-TERM DEBT	538,827	188,017
DEFERRED INCOME TAX LIABILITY	11,153	
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 21,100,347 and 18,750,000 shares issued and outstanding	21	19
Additional paid-in capital	216,120	170,367
Accumulated other comprehensive loss	(6,050)	(223)
Deferred compensation	(2,035)	
Retained earnings	126,841	89,415
Total stockholders equity	334,897	259,578
TOTAL	$ 1,054,551	$ 536,285

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

UNAUDITED CONSOLIDATED STATEMENTS OF INCOME

FOR THE THREE MONTHS AND NINE MONTHS ENDED SEPTEMBER 30, 2004 AND 2003

(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
REVENUES:				
Oil and gas sales	$ 65,898	$ 42,272	$ 166,408	$ 133,638
Loss on oil and gas hedging activities	(2,040)	(151)	(3,615)	(8,953)
Gain on sale of marketable securities	2,380		4,762	
Gain on sale of oil and gas properties	1,000		1,000	
Interest income and other	52	87	186	180
Total	67,290	42,208	168,741	124,865
COSTS AND EXPENSES:				
Lease operating	12,957	11,288	34,650	32,108
Production taxes	3,950	2,560	10,168	8,134
Depreciation, depletion and amortization	13,010	10,212	34,500	30,675
Exploration and impairment	3,766	280	4,686	1,015
General and administrative	6,117	3,126	14,191	9,522
Interest expense	4,172	1,856	9,591	7,110
Total costs and expenses	43,972	29,322	107,786	88,564
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	23,318	12,886	60,955	36,301
INCOME TAX EXPENSE:				
Current	400	208	400	650
Deferred	8,601	4,688	23,129	13,144
Total income tax expense	9,001	4,896	23,529	13,794
INCOME FROM CONTINUING OPERATIONS	14,317	7,990	37,426	22,507
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE (See Note 4)				(3,905)
NET INCOME	$ 14,317	$ 7,990	$ 37,426	$ 18,602
Earnings per share from continuing operations, basic and diluted	$ 0.70	$ 0.43	$ 1.93	$ 1.20
Cumulative change in accounting principle				(0.21)

NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.70	$ 0.43	$ 1.93	$ 0.99
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	20,516	18,750	19,341	18,750
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	20,554	18,750	19,370	18,750

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

FOR THE YEAR ENDED DECEMBER 31, 2003 AND THE NINE MONTHS ENDED SEPTEMBER 30, 2004 (Unaudited)

(In thousands)

	Common Stock							
	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Total Stockholders Equity	Comprehensive Income
BALANCES January 1, 2003	18,750	$ 19	$ 53,219	$ 71,130	$ (1,550)	$	$ 122,818	
Net income				18,285			18,285	$ 18,285
Unrealized net gain on marketable securities for sale					664		664	664
Change in derivative instrument fair value					663		663	663
Conversion of Alliant note payable to equity			80,931				80,931	
Issuance of note payable			(3,000)				(3,000)	
Phantom equity plan contribution			10,666				10,666	
Tax basis step-up			28,551				28,551	
BALANCES December 31, 2003	18,750	19	170,367	89,415	(223)		259,578	$ 19,612
Net income (unaudited)				37,426			37,426	$ 37,426
Change in fair value of marketable securities for sale (unaudited)					3,741		3,741	3,741
Realized net gain on marketable securities for sale (unaudited)					(4,835)		(4,835)	(4,835)
Change in derivative instrument fair value (unaudited)					(4,733)		(4,733)	(4,733)
Issuance of stock (unaudited)	2,237	2	43,296				43,298	
Deferred compensation stock issued (unaudited)	113		2,457			(2,457)		
Amortization of deferred compensation (unaudited)						422	422	
BALANCES September 30, 2004 (unaudited)	21,100	$ 21	$ 216,120	$ 126,841	$ (6,050)	$ (2,035)	$ 334,897	$ 31,599

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

UNAUDITED CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2004 AND 2003 (in thousands)

	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 37,426	$ 18,601
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	34,500	30,674
Deferred income taxes	23,129	13,144
Amortization of debt issuance costs and debt discount	1,025	860
Accretion of tax sharing agreement	1,800	
Amortization of deferred compensation	422	
Gain on sale of marketable securities	(4,835)	
Gain on sale of oil and gas properties	(1,000)	
Impairment of oil and gas properties	2,152	
Cumulative change in accounting principle		3,905
Changes in assets and liabilities:		
Accounts receivable	(6,466)	1,018
Income taxes and other receivable		204
Other assets	(3,652)	1,452
Asset retirement obligations	(321)	(128)
Production participation plan liability	542	(650)
Other current liabilities	12,144	5,874
Net cash provided by operating activities	96,866	74,954
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(445,340)	(6,466)
Drilling capital expenditures	(52,782)	(26,603)
Proceeds from sale of marketable securities	5,420	
Proceeds from sale of oil and gas properties	1,000	
Equity Oil Company cash paid in excess of cash received	(256)	
Acquisition of partnership interests, net of cash received		(4,453)
Net cash used by investing activities	(491,958)	(37,522)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Advances from Alliant		460
Issuance of long-term debt	583,890	
Payments on long-term debt	(214,000)	
Debt issuance costs	(11,022)	(218)
Net cash provided (used) by financing activities	358,868	242
NET CHANGE IN CASH AND CASH EQUIVALENTS	(36,224)	37,674
CASH AND CASH EQUIVALENTS:		
Beginning of period	53,585	4,833

End of period	$ 17,361	$ 42,507
SUPPLEMENT CASH FLOW DISCLOSURES:		
Cash paid for income taxes	$ 885	$ 446
Cash paid for interest	$ 3,592	$ 5,726
NONCASH FINANCING ACTIVITIES:		
Issuance of common stock for Equity Oil Company common stock	$ 43,298	
Alliant debt converted to equity	$	$ 80,931

See notes to unaudited consolidated financial statements.

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NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

SEPTEMBER 30, 2004

(In thousands, except per share data)

1. BASIS OF PRESENTATION

Description of Operations Whiting Petroleum Corporation (Whiting or the Company) is a Delaware corporation that prior to its initial public offering in November 2003 was a wholly owned indirect subsidiary of Alliant Energy Corporation (Alliant Energy or Alliant), a holding company whose primary businesses are utility companies. Just prior to the initial public offering of Whiting s common stock, the Company in effect split its common stock, issuing 18,330 shares for the 1 previously held by Alliant Energy. All periods presented have been adjusted to reflect the current capital structure. Whiting acquires, develops and explores for producing oil and gas properties primarily in the Gulf Coast/Permian Basin, Rocky Mountains, Michigan, and Mid-Continent regions of the United States.

Consolidated Financial Statements The unaudited consolidated financial statements include the accounts of Whiting and its subsidiaries, all of which are wholly owned, together with its pro rata share of the assets, liabilities, revenue and expenses of limited partnerships in which Whiting is the sole general partner. The financial statements have been prepared in accordance with generally accepted accounting principles for interim financial reporting. All significant intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. Except as disclosed herein, there has been no material change to the information disclosed in the notes to consolidated financial statements included in Whiting s Annual Report on Form 10-K for the year ended December 31, 2003. It is recommended that these unaudited consolidated financial statements be read in conjunction with the audited consolidated financial statements and notes included in the Company s Form 10-K.

Earnings Per Share Basic net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding during each period. Diluted net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding and other dilutive securities. The only securities considered dilutive are the Company s unvested restricted stock awards. The dilutive effect of these securities was immaterial to the calculation.

2. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting is exposed to market risk in the pricing of its oil and gas production. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Periodically, Whiting utilizes traditional swap and collar arrangements to mitigate the impact of oil and gas price fluctuations related to its sales of oil and gas. The Company attempts to qualify the majority of these instruments as cash flow hedges for accounting purposes.

During the first nine months of 2004 and 2003, the Company recognized losses of $3,615 and $8,953, respectively, related to its hedging activities. In addition, at September 30, 2004, Whiting s remaining cash flow hedge positions resulted in a pre-tax liability of $9,850 of which $6,050 was recorded as a component of accumulated other comprehensive income and $3,000 was recorded as a decrease to the deferred tax liability. See Note 5 for restrictions in our credit agreement relating to hedging activities.

3. MARKETABLE SECURITIES

As of December 31, 2003, the Company held an investment in a publicly traded security classified as available-for-sale (included in other long term-assets). The original cost to the Company was $585. During

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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the nine months ended September 30, 2004, the Company sold its holdings for $5,420 realizing a gain on sale of $4,835. As of December 31, 2003, the Company recorded an unrealized holding gain of $1,782 of which $1,094 was recorded as a component of accumulated other comprehensive income and $688 was recorded as a decrease to the deferred tax asset.

4. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This Statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize the fair value of asset retirement obligations in the financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to the Company, this Statement applies directly to the plug and abandonment liabilities associated with the Company s net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and the discount is accreted at the end of each accounting period through charges to depreciation, depletion and amortization expense. If the obligation is settled for other than the carrying amount, then a gain or loss is recognized upon settlement.

The Company s estimated liability for plugging and abandoning its oil and natural gas wells and certain obligations for onshore and offshore facilities in California is discounted using a credit-adjusted risk-free rate of approximately 7%. Upon adoption of SFAS No. 143, the Company recorded an increase to its discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

The following table provides a reconciliation of the Company s asset retirement obligations for the nine months ended September 30, 2004 and the year ended December 31, 2003.

	Nine Months Ended September 30, 2004	Year Ended December 31, 2003
Beginning asset retirement obligation	$ 23,021	$ 4,232
SFAS 143 adoption		16,458
Additional liability incurred	6,588	996
Accretion expense	1,214	1,482
Liabilities settled	(321)	(147)
Ending asset retirement obligation	$ 30,502	$ 23,021

No revisions have been made to the timing or the amount of the original estimate of undiscounted cash flows during 2003 or the first nine months of 2004.

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5. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2004 and December 31, 2003:

	September 30, 2004	December 31, 2003
7 1/4% Senior Subordinated Notes due 2012	$ 150,697	$
Credit Facility	$ 435,000	$ 185,000
Alliant	$ 3,130	$ 3,017
Total debt	$ 588,827	$ 188,017
Less current portion of long-term debt	$ (50,000)	$
Long-term debt	$ 538,827	$ 188,017

Credit Facility On September 23, 2004, Whiting Oil and Gas Corporation entered into an amended and restated $750.0 million credit agreement with a syndicate of banks. The new credit agreement increases the Company s borrowing base to $480.0 million from $195.0 million under the prior credit agreement. The borrowing base under the credit agreement is determined in the discretion of the lenders based on the collateral value of the proved reserves that have been mortgaged to the lenders and is subject to regular redetermination on May 1 and November 1 of each year as well as special redeterminations described in the credit agreement. On September 23, 2004, Whiting Oil and Gas Corporation borrowed $400.0 million under the credit agreement in order to (i) refinance the entire outstanding balance under the prior credit agreement and (ii) fund its $345.0 million acquisition of oil and natural gas producing properties from CrownQuest Operating LLC. On September 30, 2004, an additional $35.0 million was borrowed to fund an additional acquisition.

The credit agreement provides for interest only payments until September 23, 2008, when the entire amount borrowed is due. In addition, the credit agreement provides that Whiting Oil and Gas Corporation will make principal payments under the credit agreement by May 1, 2005 to reduce the principal balance to $385.0 million. Whiting Oil and Gas Corporation may, throughout the four year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect from time to time. Interest accrues, at Whiting Oil and Gas Corporation s option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. Whiting Oil and Gas Corporation has consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.250% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense.

The credit agreement contains restrictive covenants that may limit the Company s ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders and requires us to maintain a debt to EBITDAX (as defined in the credit agreement) ratio of less than 3.5 to 1 and a working capital ratio of greater than 1 to 1. The credit agreement also requires the Company to hedge at least 60% but not more than 75% of its total forecasted proved developed producing production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps, with a minimum floor price of $35 per barrel of oil or $4.50 per million British Thermal Units (MMBtu). After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to

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a maximum of 75% of our forecasted proved developed producing production. In addition, while the credit agreement allows the Company s subsidiaries to make payments to the Company so that it may pay interest on its senior subordinated notes, it does not allow the Company s subsidiaries to make payments to it to pay principal on the senior subordinated notes. The Company was in compliance with its covenants under the credit agreement as of September 30, 2004. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation s assets. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee and Equity Oil Company has mortgaged substantially all of its assets as security for its guarantee.

7 1/4% Senior Subordinated Notes due 2012 On May 11, 2004, the Company issued, in a private placement, $150.0 million aggregate principal amount of its 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to refinance debt outstanding under the Company s credit agreement. The notes were issued at 99.26% of par and the associated discount is being amortized to interest expense over the term of the notes. On July 12, 2004, the Company completed an exchange offer in which it issued $150.0 million aggregate principal amount of new 7 1/4% senior subordinated notes due 2012 registered under the Securities Act of 1933 in exchange for the old notes. The notes are unsecured obligations of the Company and are subordinated to all of the Company s senior debt. The indenture governing the notes contains various restrictive covenants that may limit the Company s and its subsidiaries ability to, among other things, pay cash dividends, redeem or repurchase the Company s capital stock or the Company s subordinated debt, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may limit the discretion of the Company s management in operating the Company s business. In addition, Whiting Oil and Gas Corporation s credit agreement restricts the ability of the Company s subsidiaries to make payments to the Company. The Company was in compliance with these covenants as of September 30, 2004. Three of the Company s subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company (the Guarantors), have fully, unconditionally, jointly and severally guaranteed the Company s obligations under the notes. All of the Company s subsidiaries other than the Guarantors are minor within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission, and the Company has no independent assets or operations.

Interest Rate Swap In August 2004, we entered into an interest rate swap contract to hedge the fair value of $75 million of our 7 1/4% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the short cut method of assessing effectiveness under the provisions of Statement of Financial Accounting Standards No. 133, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that we receive the fixed rate of 7.25% and pay the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus our margin of 2.345% is less than 7.25%, we receive a payment from the counterparty equal to the difference in rate times $75 million for the six month period. When LIBOR plus our margin of 2.345% is greater than 7.25%, we pay the counterparty an amount equal to the difference in rate times $75 million for the six month period. As of September 30, 2004, we have recorded a long term derivative asset of $1.7 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding debt increase.

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Long-Term Debt Payable to Alliant Energy In conjunction with the Company s initial public offering in November 2003, the Company issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The promissory note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005.

Alliant Energy had loaned the Company an aggregate $80.5 million as of December 31, 2002. The note bore interest at a floating rate which ranged from 6.9% to 4.4% during the first quarter of 2003. On March 31, 2003, Alliant Energy converted its outstanding intercompany balance of $80.9 million to equity of the Company.

6. EQUITY INCENTIVE PLAN

The Company s Board of Directors adopted the Whiting Petroleum Corporation 2003 Equity Incentive Plan on September 17, 2003. Two million shares of the Company s common stock have been reserved for issuance under this plan. No participating employee may be granted options for more than 300,000 shares of common stock, stock appreciation rights with respect to more than 300,000 shares of common stock or more than 150,000 shares of restricted stock during any calendar year. This plan prohibits the repricing of outstanding stock options without stockholder approval. During the first three quarters of 2004, the Company granted 112,921 shares of restricted stock under this plan. The shares of restricted stock were recorded at fair value of $2.5 million and are being amortized to general and administrative expense over their three year vesting period.

7. PRODUCTION PARTICIPATION PLAN

The Company maintains a Production Participation Plan for all employees. On an annual basis, interests in oil and gas properties acquired or developed during the year are allocated to the plan on a discretionary basis. Once allocated, the interests (not legally conveyed) are fixed and plan participants generally vest ratably over five years. Forfeitures are re-allocated among other Plan participants. Allocations prior to 1995 consisted of 2% 3% overriding royalty interests. Allocations since 1995 have been 2% 5% net revenue interests. Payments to participants of the plan are made annually in cash after year end.

Effective April 23, 2004, the Production Participation Plan was amended and restated. Specifically, the plan was amended to (1) provide that, for years 2004 and beyond, employees will vest at a rate of 20% per year with respect to the income allocated to the plan for such year; (2) provide that employees will become fully vested at age 65, regardless of when their interests would otherwise vest; and (3) provide that, for pools for years 2004 and beyond, if there are forfeitures, the interests will inure to the benefit of the Company.

8. TAX SEPARATION AND INDEMNIFICATION AGREEMENT WITH ALLIANT ENERGY

In connection with Whiting s initial public offering in November 2003, the Company entered into a tax separation and indemnification agreement with Alliant Energy. Pursuant to this agreement, the Company and Alliant Energy made a tax election with the effect that the tax basis of the assets of Whiting and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to reflect the new tax basis of the Company s assets. This additional basis is expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by Whiting.

Under this agreement, the Company has agreed to pay to Alliant Energy 90% of the future tax benefits the Company realizes annually as a result of this step-up in tax basis for the years ending on or prior to

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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December 31, 2013. Such tax benefits will generally be calculated by comparing the Company s actual taxes to the taxes that would have been owed by the Company had the increase in basis not occurred. In 2014, Whiting will be obligated to pay Alliant Energy 90% of the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years. Future tax benefits in total will approximate $62 million. The Company has estimated total payments to Alliant will approximate $49 million given the discounting affect of the final payment in 2014. The Company has discounted all cash payments to Alliant at the date of the Tax Separation Agreement.

The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders equity. The Company will monitor the estimate of when payments will be made and adjust the accretion of this liability on a prospective basis. During the first nine months of 2004, the Company recognized $1.8 million of accretion expense which is included as a component of interest expense.

There is a provision in the Tax Separation Agreement that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in a corresponding adjustment of the Alliant liability. For purposes of this calculation, management has assumed that no such change will occur during the term of this agreement.

9. ACQUISITIONS

Permian Basin Properties

On September 23, 2004, we acquired interests in seventeen fields in the Permian Basin of West Texas and Southeast New Mexico, including interests in key fields such as Parkway Field in Eddy County, New Mexico; Would Have and Signal Peak Fields in Howard County, Texas; Keystone Field in Winkler County, Texas; and the DEB Field in Gaines County, Texas. The purchase price was $345.0 million in cash and was funded through borrowings under our bank credit agreement.

For the year ended December 31, 2003, these properties reported revenues in excess of direct operating expenses of $72.1 million. As of October 1, 2004, these properties had 250.0 Bcfe of estimated proved reserves, of which 17.8% were natural gas and 58.9% were classified as proved developed, and had a pre-tax PV10 value of estimated proved reserves of $673.6 million. The estimated October 2004 average daily production for these properties is approximately 36.4 MMcfe, implying an average reserve life of 18.8 years. We operate approximately 72% of the average daily production from these properties.

Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our common stock to Equity s shareholders and repaid all of Equity s outstanding debt of $29.0 million under its credit facility. Equity s operations are focused primarily in California, Colorado, North Dakota and Wyoming.

For the year ended December 31, 2003, Equity reported income from continuing operations of $2.4 million, net cash provided by operating activities of $11.5 million and production of 6.6 Bcfe (45% natural gas). As of October 1, 2004, Equity had 103.6 Bcfe of estimated proved reserves, of which 40.6% were natural gas and 69% were classified as proved developed, and had a pre-tax PV10% value of estimated proved reserves of approximately $217.6 million. The estimated October 2004 average daily production from these properties is approximately 16.1 MMcfe, implying an average reserve life of 17.6 years.

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Based on the purchase price of $72.6 million and estimated proved reserves of 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Other Cash Acquisitions of Properties

On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming from an undisclosed seller. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. We operate two of the fields and have an 84% average working interest in those fields. As of October 1, 2004, these interests had 40.1 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 8.6 MMcfe, implying an average reserve life of 12.7 years. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah from an undisclosed seller. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. As of October 1, 2004, these interests had 32.6 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 6.1 MMcfe, implying an average reserve life of 14.7 years. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas from Delta Petroleum Corporation. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. We operate two of the fields and have a 93% average working interest in those fields. As of October 1, 2004, these interests had 13.9 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 3.5 MMcfe, implying an average reserve life of 11.0 years. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe of estimated proved reserves.

As these acquisitions were recorded using the purchase method of accounting, the results of operations from the acquisitions are included with our results from the respective acquisition dates noted above. The table below summarizes the preliminary allocation of the purchase price of each transaction based on the acquisition date fair values of the assets acquired and the liabilities assumed (in thousands):

	Permian Basin	Equity Oil	Other Cash Acquisitions

Purchase Price:			
Cash paid, net of cash received	$ 345,000	$ 256	$ 98,500
Debt assumed		29,000	
Stock issued		43,298	
Total	$ 345,000	$ 72,554	$ 98,500
Allocation of Purchase Price:			
Working capital		$ 3,779	
Oil and gas properties	$ 345,000	82,776	$ 98,500
Deferred income taxes		(10,418)	
Other non-current liabilities		(3,583)	
Total	$ 345,000	$ 72,554	$ 98,500

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NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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The following table reflects the unaudited pro forma results of operations for the year ended December 31, 2003 and for the three and nine month periods ended September 30, 2004 as though the above acquisitions had occurred on the first day of each period presented. The pro forma amounts for the three and nine month periods ended September 30, 2004 include only the activity from the beginning of the period to the closing date of the acquisitions. (in thousands, except per share amounts):

		Pro Forma			
	Historical Whiting	Permian Basin	Equity Oil	Other Cash Acquisitions	Pro Forma Consolidated
Year ended December 31, 2003					
Total revenues	$ 167,381	$ 91,246	$ 27,825	$ 28,592	$ 315,044
Net income from continuing operations	22,190	19,028	6,050	3,823	51,091
Net income	18,285	19,028	6,050	3,823	47,186
Net income per common share-basic and diluted	0.98	0.91	0.29	0.18	2.25
Three months ended September 30, 2004					
Total revenues	$ 67,290	$ 19,300	$ 1,489	$ 6,123	$ 94,202
Net income	14,317	4,649	377	1,205	20,548
Net income per common share-basic and diluted	0.70	0.22	0.02	0.06	0.98
Three months ended September 30, 2003					
Total revenues	$ 42,208	$ 21,476	$ 6,705	$ 7,117	$ 77,506
Net income	7,990	4,733	1,408	955	15,086
Net income per common share-basic and diluted	0.43	0.23	0.07	0.05	0.72
Nine months ended September 30, 2004					
Total revenues	$ 168,741	$ 58,443	$ 15,980	$ 23,553	$ 266,717
Net income	$ 37,426	$ 11,614	$ 4,047	$ 4,457	$ 57,545
Net income per common share-basic and diluted	$ 1.93	$ 0.55	$ 0.19	$ 0.21	$ 2.74
Nine months ended September 30, 2003					
Total revenues	$ 124,865	$ 74,070	$ 20,101	$ 21,723	$ 240,759
Net income from continuing operations	22,507	16,809	3,866	3,092	46,274
Net income	18,602	16,809	3,866	3,092	42,369
Net income per common share-basic and diluted	0.99	0.80	0.18	0.15	2.02

10. QUARTERLY FINANCIAL DATA

The following is a summary of the unaudited financial data for each quarter for the nine months ended September 30, 2004 (in thousands, except per share data):

	Three Months Ended		
	March 31, 2004	June 30, 2004	September 30, 2004
Nine months ended September 30, 2004:			
Oil and gas sales	$ 47,636	$ 52,874	$ 65,898
Net income	9,638	13,471	14,317
Basic net income per share	0.51	0.72	0.70

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Whiting Petroleum Corporation:

We have audited the accompanying statements of revenues and direct operating expenses of the properties (the Permian Basin Acquisition Properties) acquired by Whiting Petroleum Corporation (the Company) from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. and Baytech, L.L.P. for each of the three years in the period ended December 31, 2003. These statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the statements. We believe that our audits provide a reasonable basis for our opinion.

The accompanying statements were prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission as described in Note 1 to the statements and are not intended to be a complete presentation of the Company s interests in the properties described above.

In our opinion, the statements referred to above present fairly, in all material respects, the revenues and direct operating expenses, described in Note 1, of the Permian Basin Acquisition Properties for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado

October 15, 2004

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PERMIAN BASIN ACQUISITION PROPERTIES

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES (in thousands)

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001 AND THE SIX MONTHS ENDED

JUNE 30, 2004 and 2003 (UNAUDITED)

	Six Months Ended June 30,		Year Ended December 31,		
	2004	2003	2003	2002	2001
	(Unaudited)				
REVENUES Oil and gas production	$ 39,143	$ 52,594	$ 91,246	$ 61,903	$ 69,682
DIRECT OPERATING EXPENSES:					
Lease operating expense	8,244	6,900	14,031	11,252	10,755
Production taxes	2,317	2,899	5,159	3,350	4,149
Total direct operating expenses	10,561	9,799	19,190	14,602	14,904
Revenues in excess of direct operating expenses	$ 28,582	$ 42,795	$ 72,056	$ 47,301	$ 54,778

See accompanying notes to the Statements of Revenues and Direct Operating Expenses.

PERMIAN BASIN ACQUISITION PROPERTIES

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001 AND THE SIX MONTHS ENDED

JUNE 30, 2004 and 2003 (UNAUDITED)

1. BASIS OF PRESENTATION

On September 23, 2004, Whiting Petroleum Corporation (the Company) completed its acquisition of interests in seventeen oil and natural gas fields located in the Permian Basin of West Texas and Southeast New Mexico from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. and Baytech, L.L.P. (collectively, the Sellers) for $345 million. The properties are referred to herein as the Permian Basin Acquisition Properties .

The accompanying statements of revenues and direct operating expenses were derived from the historical accounting records of the Sellers and prior operators and reflect the revenues and direct operating expenses of the Permian Basin Acquisition Properties. Such amounts may not be representative of future operations. The statements do not include depreciation, depletion and amortization, general and administrative expenses, income taxes or interest expense as these costs may not be comparable to the expenses expected to be incurred by the Company on a prospective basis.

The Sellers used the sales method to record oil revenue, whereby revenue is recognized based on the amount of oil sold to purchasers. With respect to the gas sales, the entitlements method was used for recording revenues. Under this approach, revenue is recognized for the Sellers share of natural gas produced regardless of whether the Sellers had taken its share of the related production. The effect on revenues of production imbalances is not material. Direct operating expenses include payroll, leases and well repairs, production taxes, maintenance, utilities and other direct operating expenses.

The process of preparing financial statements in conformity with generally accepted principles requires the use of estimates and assumptions regarding certain types of revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Historical financial statements reflecting financial position, results of operations and cash flows required by generally accepted accounting principles are not presented as such information is not readily available on an individual property basis and not meaningful to the Permian Basin Acquisition Properties. Accordingly, the historical statements of revenue and direct operating expenses are presented in lieu of the financial statements required under Rule 3-05 of the Securities and Exchange Commission Regulation S-X.

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PERMIAN BASIN ACQUISITION PROPERTIES

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001 AND THE SIX MONTHS ENDED

JUNE 30, 2004 and 2003 (UNAUDITED)

2. SUPPLEMENTAL DISCLOSURES OF OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Reserve Quantities The following table summarizes the estimated quantities of proved oil and gas reserves of the Permian Basin Acquisition Properties. These amounts were derived from reserve estimates prepared by Cawley, Gillespie & Associates, Inc. as of July 1, 2004, adjusted only for production in prior periods. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. The oil and gas reserves stated below are attributable solely to properties within the United States.

	Oil (Mbbls)	Gas (Mmcf)
Balance January 1, 2001	39,127	76,515
Production	(1,415)	(8,682)
Balance December 31, 2001	37,712	67,833
Production	(1,948)	(5,333)
Balance December 31, 2002	35,764	62,500
Production	(2,166)	(5,878)
Balance December 31, 2003	33,598	56,622
Production	(777)	(2,413)
Balance June 30, 2004	32,821	54,209
Proved developed reserves:		
December 31, 2001	23,157	52,001
December 31, 2002	21,209	46,668
December 31, 2003	19,043	40,790
June 30, 2004	18,266	38,377

Standardized Measure of Discounted Future Net Cash Flows The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with the provisions of SFAS No. 69. Future cash inflows were computed by applying prices at year end to estimated future production, less estimated future expenditures (based on year end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expense. Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows, less the tax basis of properties involved. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of the Permian Basin Acquisition Properties (in thousands).

	2003	2002	2001
Future cash flows	$ 1,210,949	$ 1,187,059	$ 727,071
Future production costs	(416,440)	(429,143)	(414,835)
Future development costs	(73,031)	(90,082)	(95,872)
Future income tax expense	(110,581)	(89,874)	
Future net cash flows	610,897	577,960	216,364
10% annual discount for estimated timing of cash flows	(304,410)	(287,997)	(107,814)
Standardized measure of discounted future net cash flows	$ 306,487	$ 289,963	$ 108,550

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PERMIAN BASIN ACQUISITION PROPERTIES

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The changes in the standardized measure of discounted future net cash flows relating to proved oil and gas reserves are as follows (in thousands):

	2003	2002	2001
Beginning of year:	$ 289,963	$ 108,550	$ 376,220
Sale of oil and gas produced, net of production costs	(72,056)	(47,301)	(54,778)
Net changes in prices and production costs	48,413	257,159	(368,691)
Development costs	17,051	5,790	3,698
Net change in income taxes	(10,389)	(45,090)	103,471
Accretion of discount	33,505	10,855	48,630
End of Year	$ 306,487	$ 289,963	$ 108,550

Average wellhead prices in effect at December 31, 2003, 2002 and 2001 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows (in thousands):

	2003	2002	2001
Oil (per Bbl)	$ 28.29	$ 27.04	$ 15.88
Gas (per Mcf)	4.60	3.52	1.89

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GLOSSARY OF OIL AND NATURAL GAS TERMS

We have included below the definitions for certain oil and natural gas terms used in this prospectus:

3-D seismic Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used in this prospectus in reference to oil and other liquid hydrocarbons.

Bcf One billion cubic feet of natural gas.

Bcfe One billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe Barrels of oil equivalent, determined using the ratio of six thousand cubic feet of natural gas to one barrel of oil.

Bopd Barrels of oil per day.

completion The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

horizontal re-entry well A new well in which a pre-existing wellbore is used as the starting point of a new horizontal borehole. Drilling a horizontal re-entry well typically involves milling a hole in the casing of the pre-existing wellbore and drilling hundreds or thousands of feet from the pre-existing wellbore.

Mbo One thousand barrels of oil.

Mcf One thousand cubic feet of natural gas.

*Mcf/*d One Mcf per day.

Mcfe One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

*Mcfe/*d One Mcfe per day.

MMbbls millions of barrels of oil or other liquid hydrocarbons.

MMboe One million barrels of oil equivalent.

MMbtu One million British Thermal Units.

MMcf One million cubic feet of natural gas.

MMcf/d One MMcf per day.

MMcfe One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d One MMcfe per day.

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PDNP Proved developed nonproducing.

PDP Proved developed producing.

plugging and abandonment Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

PUD Proved undeveloped.

pre-tax PV10% The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using price and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or Federal income taxes and discounted using an annual discount rate of 10%.

reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

working interest The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

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7,500,000 Shares

Whiting Petroleum Corporation

Common Stock

PROSPECTUS

Merrill Lynch & Co.

A.G. Edwards

Banc of America Securities LLC

JPMorgan

Raymond James

Petrie Parkman & Co.

KeyBanc Capital Markets

Simmons & Company International

, 2004